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BEFORE THE ARIZONA CORPORATION COMMISSION

JIM IRVIN  
Commissioner - Chairman  
RENZ D. JENNINGS  
Commissioner  
CARL J. KUNASEK  
Commissioner

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IN THE MATTER OF THE APPLICATION  
OF TUCSON ELECTRIC POWER  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01933A-98-0471

IN THE MATTER OF THE FILING OF  
TUCSON ELECTRIC POWER COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01933A-97-0772

IN THE MATTER OF THE APPLICATION  
OF ARIZONA PUBLIC SERVICE  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01345A-98-0473

IN THE MATTER OF THE FILING OF  
ARIZONA PUBLIC SERVICE COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN  
THE PROVISION OF ELECTRIC SERVICES  
THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

NOTICE OF FILING

Pursuant to the Commission's Procedural Orders dated November 13 and November 25, 1998, counsel for Cyprus Climax Metals Company, ASARCO Incorporated, Enron Corp. and Arizonans for Electric Choice and Competition herein undersigned, hereby provides notice of the

1 filing of the Direct Testimonies of Kevin C. Higgins, Alan E. Rosenberg, Michael D. McElrath,  
2 Jerry Turner, Sydney Hoff Hay, Lee Jestings and Thomas Edward Delaney in the above-  
3 captioned dockets.

4 DATED this 30<sup>th</sup> day of November, 1998.

5 FENNEMORE CRAIG, P.C.

6  
7 By 

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Arizonans for Electric Choice and Competition

12 ORIGINAL AND TEN COPIES  
13 of the foregoing hand-delivered  
14 this 30<sup>th</sup> day of November, 1998, to:

15 Arizona Corporation Commission  
16 Docket Control  
17 1200 West Washington Street  
18 Phoenix, Arizona 85007

19 TWO COPIES OF THE FOREGOING  
20 hand-delivered this 30<sup>th</sup> day  
21 of November, 1998 to:

22 Jerry Rudibaugh, Chief Hearing Officer  
23 Hearing Division  
24 Arizona Corporation Commission  
25 1200 West Washington  
26 Phoenix, Arizona 85007

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hand-delivered this 30<sup>th</sup> day  
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Jim Irvin  
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Phoenix, Arizona 85007

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

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DOCKET NO. ~~E-01933A-97-0772~~

IN THE MATTER OF THE APPLICATION  
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COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01345A-98-0473

IN THE MATTER OF THE FILING OF  
ARIZONA PUBLIC SERVICE COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN  
THE PROVISION OF ELECTRIC SERVICES  
THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

**DIRECT TESTIMONY OF KEVIN C. HIGGINS**

On Behalf of ASARCO Incorporated, Cyprus Climax Metals Company,  
and Arizonans for Electric Choice and Competition

1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

3 Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

4 A. I am employed by Energy Strategies, Inc. (ESI) as a senior associate. ESI is a private  
5 consulting firm specializing in the economic and policy analysis applicable to energy  
6 production, transportation, and consumption.

7 Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

8 A. My testimony is being sponsored by Arizonans for Electric Choice and Competition<sup>1</sup>,  
9 Cyprus Climax Metals, and Asarco.

10 Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND?

11 A. My academic background is in economics, and I have completed all course work and  
12 examinations toward the Ph.D. in Economics at the University of Utah, and have served  
13 on the adjunct faculties of both the University of Utah and Westminster College. Prior to  
14 joining ESI, I held policy positions in state and local government. From 1983 to 1990, I  
15 was economist, then assistant director, for the Utah Energy Office, where I testified  
16 regularly before the Utah Public Service Commission on matters involving structural  
17 change in the provision of energy services, including introduction of retail competition in  
18 the natural gas industry, implementation of rules governing small power production and  
19 cogeneration, joint ownership of electric transmission facilities, and the merger between  
20 major electric utilities. From 1991 to 1994, I was chief of staff to the chairman of the  
21 Salt Lake County Commission, one of the larger municipal governments in the western  
22

23 <sup>1</sup> Arizonans for Electric Choice and Competition is a coalition of companies and associations in favor of  
24 competition and includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes,  
25 Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Enron, Homebuilder's of Central Arizona,  
26 Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries,  
Arizona Multi-housing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona  
Association of General Contractors, and Arizona Retailers Association.

1 U.S., where I was responsible for development and implementation of a broad spectrum  
2 of public policy. In 1995, I joined ESI, where I assist private and public-sector clients in  
3 the area of energy-related economic and policy analysis, including the provision of expert  
4 testimony. A more detailed description of my qualifications is contained in Exhibit KCH-  
5 1, attached to this testimony.

6 Q. WHAT HAS BEEN YOUR INVOLVEMENT IN THE ELECTRIC INDUSTRY  
7 RESTRUCTURING EFFORT IN ARIZONA?

8 A. For much of 1996, I was involved in the workshop process conducted by the Arizona  
9 Corporation Commission to develop rules governing the implementation of retail access.  
10 In 1997, I participated in most of the Working Groups established by the Commission,  
11 serving as a consumer representative on the Stranded Cost Working Group; as part of that  
12 effort, I participated in each of the Working Group's three subcommittees. I also  
13 participated actively in the Reliability & Safety, Customer Selection, ISO, and  
14 Unbundled Services & Standard Offer Working Groups established by the Commission.  
15 Concurrently, I have been actively involved in the Desert STAR feasibility assessment,  
16 participating on the Steering Committee, and in the Pricing and Operations Working  
17 Groups.

18 In 1998, I provided direct and rebuttal testimony before this Commission on  
19 stranded cost recovery in the electric competition hearing, and provided extensive  
20 comments to the SRP Board as part of its effort to implement retail competition. I have  
21 also been heavily involved in addressing transmission access issues; I serve on the Board  
22 of the Arizona Independent Scheduling Administrator (AISA) as a representative of end-  
23 users and am chairing its Operating Committee, which is responsible for drafting the  
24 AISA's Protocols Manual.  
25  
26

1 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY TODAY?

2 R. My testimony addresses the Settlement Agreements between Staff and Arizona Public  
3 Service (APS) and between Staff and Tucson Electric Power (TEP). I recommend that the  
4 Commission *not* approve either of these Settlements in their current form. It is my  
5 opinion that the proposed transmission asset sale by APS is not an acceptable tradeoff for  
6 the stranded cost terms in the APS Settlement. It is also my opinion that the "adders" to  
7 the APS and TEP Market Generation Credits are not large enough to allow meaningful  
8 competition to occur. I recommend specific modifications to the Settlements that are  
9 necessary to correct significant flaws, which, if left uncorrected, will harm customers and  
10 impede the introduction of competition. Specifically, I recommend that:

- 11 1) The APS Settlement needs to be modified to close a loophole that may allow the  
12 utility to collect more than 100 percent of its stranded cost. The loophole can be  
13 closed by providing for the recovery of regulatory assets through market prices  
14 whenever market prices are high enough to make this possible.
- 15 2) The TEP Settlement needs to be modified to prevent TEP from using any  
16 proceeds from generation assets sales to purchase transmission assets, if such use  
17 of proceeds would prevent customers from realizing the lowest possible stranded  
18 cost charges.
- 19 3) The TEP Settlement needs to be modified to add customer protection language  
20 regarding the criteria for declaring a failed auction.
- 21 4) The TEP Settlement should not be approved until a plan is developed that will  
22 protect customers from the "stipulated loss values" penalties contained in various  
23 TEP generation leases.  
24  
25  
26

- 1 5) Both the APS and TEP Settlements need to be modified to require an unbundled,  
2 Must-run fixed-cost charge that will serve as a credit against the retail access  
3 customer's bill (similar to the transmission charge).  
4 6) Both the APS and TEP Settlements need to be modified to require an adjustment  
5 to the Market Generation Credit to account for the incidence of Must-run variable  
6 cost charges that are levied on Scheduling Coordinators.  
7 7) The APS Unbundled Tariff should be modified to provide distribution charges  
8 that are differentiated according to the voltage level at which service is taken, for  
9 customers taking Extra Large Direct Access General Service.  
10 8) The one percent rate reductions scheduled for 1999 and 2000 in the APS  
11 Settlement should be spread across all unbundled services to the greatest extent  
12 possible, instead of being limited to generation service.  
13 9) Both the APS and TEP Settlements need to be modified to make it clear that, for  
14 all customers -- including special contract customers -- the cost basis from which  
15 the CTC is calculated is the effective rate these customers now pay in their rates  
16 or contracts.

17 In addition, it is critical that the Commission adopt the recommendations by Alan  
18 Rosenberg to increase the size of -- and refrain from skewing -- the Market Generation  
19 Credit "adder," and to place appropriate limitations on the return TEP is allowed to earn  
20 on its stranded cost.

21 **Structure of the Settlements**

22 Q. WHAT IS YOUR ASSESSMENT OF THE BASIC STRUCTURE OF THE  
23 SETTLEMENTS?

24 A. The APS Settlement departs from the path laid out in the Commission's stranded cost  
25 Order in two very major respects: (1) APS is to receive 100 percent of its stranded cost  
26

1 claim<sup>2</sup> without divesting its generation, and (2) APS is to recover its stranded cost claims  
2 using the net revenues lost approach. The justification for these changes is APS'  
3 willingness to sell its EHV transmission assets to TEP. From a customer's point of view,  
4 I do not consider this to be an acceptable tradeoff.

5 Q. WHAT IS WRONG WITH THIS TRADEOFF?

6 A. First, consider that the APS stranded cost recovery program is substantially the same as  
7 the one the Commission has already rejected, when it found that the "Net Revenues Lost  
8 Methodology proposed by APS provides little incentive for customers to utilize another  
9 competitive service."<sup>3</sup> This finding of fact still holds true. Among its many  
10 shortcomings, the APS stranded cost approach: (1) makes no distinction as to whether a  
11 particular generation-related cost should even qualify as "stranded", and (2) provides no  
12 credit to customers for the market value of APS generation that accrues to the utility after  
13 the recovery period. In addition, the APS Settlement provides no requirement to mitigate  
14 stranded costs beyond what is necessary to achieve two one-percent rate reductions.

15 Thus, even if the transmission sale made great sense in its own right – which is far  
16 from clear – the onerous stranded cost terms being accepted as part of the tradeoff will  
17 preclude customers from realizing any transmission benefits in the first place.

18 Q. DOESN'T THE SALE OF APS' TRANSMISSION TO TEP REDUCE VERTICAL  
19 MARKET POWER?

20 A. It may reduce APS' vertical market power, but there is an offsetting increase in TEP's  
21 vertical market power. In addition, since part of the deal includes the APS purchase of  
22 TEP's interest in generation facilities, APS' horizontal market power is increased.  
23

24  
25 <sup>2</sup> The Settlement provides for 100 percent recovery of APS stranded cost. As I will point out below, the Settlement  
also contains a loophole that will allow APS to recover more than 100 percent of its stranded cost.

26 <sup>3</sup> Arizona Corporation Commission, Decision No. 60977, p. 22.

1 Q. WITH TEP DIVESTING ITS GENERATION, HOW CAN ACQUIRING MORE  
2 TRANSMISSION INCREASE ITS VERTICAL MARKET POWER?

3 A. The threat to competitive markets from vertical market power exists on both sides of the  
4 transmission system: the generation side and the retail sales side. TEP will continue to be  
5 a retail provider, both as a Utility Distribution Company (UDC) and as an Energy  
6 Services Provider (ESP) through an affiliate. The vertical market power hazard is that the  
7 transmission owner will favor the access needs of its affiliated retail providers –  
8 irrespective of who owns the generation. This hazard does not go away with the  
9 transmission asset sale; it is simply transferred from APS to TEP.

10 Q. ARE OTHER STEPS - OUTSIDE THE SETTLEMENTS - BEING TAKEN TO  
11 MITIGATE VERTICAL MARKET POWER?

12 A. Yes. The Competition Rules require the establishment of an Arizona Independent  
13 Scheduling Administrator (AISA) to ensure non-discriminatory access to the grid. This  
14 organization has now been formed and its stakeholder working group has made  
15 significant progress in developing transmission access protocols. The AISA will be very  
16 helpful in mitigating vertical market power. Likewise, the ultimate development of an  
17 Independent System Operator (ISO) will be an important tool for meeting this objective.

18 Q. DO YOU THINK THE FORMATION OF A TRANSCO TO RUN TRANSMISSION  
19 SYSTEM IS A GOOD IDEA?

20 A. I think the formation of a transco may have merit and is worth exploring. For that reason  
21 I commend the Staff for putting the concept of a transco on the table. However, a key  
22 characteristic of a transco is that it be completely independent of generation and retail  
23 sales interests. That is not the case with TEP. But more importantly, the potential  
24 benefits of even the purest transco do not warrant adopting the competition-stifling APS  
25 stranded cost package as part of the tradeoff.  
26

1 Q. THE SETTLEMENT INDICATES THAT THE APS STRANDED COST PACKAGE  
2 INCLUDES A 3-MILL "ADDER" TO THE PALO VERDE MARKET PRICE IN THE  
3 CALCULATION OF A CUSTOMER'S MARKET GENERATION CREDIT (MGC).  
4 SIMILARLY, THE TEP PACKAGE INCLUDES A 3.5-MILL ADDER. DON'T THESE  
5 ADDERS PROVIDE SUFFICIENT OPPORTUNITY FOR COMPETITION TO  
6 DEVELOP?

7 A. While, in general, I remain opposed to the adoption of the Net Revenues Lost method, I  
8 believe the "adders" approach can be made to work if it is set at a level that is fair to  
9 customers and assigns some responsibility to the utility for stranded cost risk. However,  
10 the adders being proposed in the Settlements do not accomplish these objectives. Too  
11 much is being asked of too little a margin.

12 First, it is important to realize that these adders are averages. For the customers  
13 most likely to be interested in the early stages of retail access – the higher-load-factor  
14 customers – the adder is significantly smaller than the average. As pointed out by APS  
15 witness Jack Davis, for a 75 percent load factor customer, the APS adder will be reduced  
16 to 2.2 mills. Out of this, the customer's Scheduling Coordinator must cover the cost of  
17 ancillary services, for this customer about .6 mill.

18 In addition, the customer's Scheduling Coordinator will be at risk for Energy  
19 Imbalance charges. Under the Open Access Transmission Tariffs proposed by both APS  
20 and TEP, a Scheduling Coordinator who under-schedules retail load by more than 1.5  
21 percent (or 2 MW, whichever is greater) in any hour is subject to a minimum 100 mill-  
22 per-kWh Energy Imbalance charge. The risk to the Scheduling Coordinator of incurring  
23 these costs will be passed on to the customers and is also to be "absorbed" by the adder.

24 Further, as I point out later in my testimony, the Settlements fail to require  
25 appropriate crediting in the unbundled tariffs for Must-run generation costs. Thus, unless  
26

1 corrected, the customer's Scheduling Coordinator must also absorb these costs from this  
2 rapidly-disappearing margin. Out of the approximately 1 mill margin remaining for the  
3 75 percent load factor customer, the ESP must cover its costs and earn its mark-up. Add  
4 to that the requirements of the solar portfolio standard, and any savings from competition  
5 have all but vanished.

6 Resolving the inadequacy of the proposed adders is addressed in the testimony of  
7 Alan Rosenberg.

8 **Loophole in the treatment of regulatory assets**

9 Q. PLEASE EXPLAIN YOUR RECOMMENDATION THAT THE APS SETTLEMENT  
10 NEEDS TO BE MODIFIED TO CLOSE A LOOPHOLE THAT MAY ALLOW THE  
11 UTILITY TO COLLECT MORE THAN 100 PERCENT OF ITS STRANDED COST.

12 A. The loophole in the Settlement involves the recovery of regulatory assets. The Settlement  
13 fails to recognize that regulatory assets only become stranded costs if the utility is unable  
14 to recover its regulatory assets at market prices. During periods when market prices are  
15 relatively high, APS ought to be able to recover some, or perhaps all, of its regulatory  
16 asset charges directly from market sales. However, the Settlement shields APS  
17 regulatory asset charges from changes in market prices, and as a result, over-recovery of  
18 APS stranded costs is a virtual certainty if this problem is not corrected.

19 Q. HOW DOES THE SETTLEMENT SHIELD APS REGULATORY ASSET CHARGES  
20 FROM CHANGES IN MARKET PRICES?

21 A. In the APS Settlement, the stranded cost charge is broken down into two components: (1)  
22 a regulatory asset charge and (2) a CTC.<sup>4</sup> The regulatory asset charge is proposed to be a  
23 separate, unbundled pricing element intended to recover approximately \$900 million in  
24 APS regulatory assets, which significantly, represents the lion's share of the utility's  
25

26 <sup>4</sup> CTC generally stands for Competitive Transition Charge; however, the Settlement also uses the term Customer Transition Charge.

1 stranded cost problem. The regulatory asset charge is proposed to be a fixed per-kWh (or  
2 per-kW) charge. Consequently, it does not vary with market prices.

3 The regulatory asset charge can be contrasted with the CTC component. The CTC  
4 is designed to be a residual that moves inversely with market prices. It is calculated by  
5 subtracting a Market Generation Credit (MGC) from the generation charge in the APS  
6 unbundled tariff. The MGC is equal to the wholesale market price of generation plus a  
7 retail adder. Thus, when market prices increase – and consequently, stranded cost  
8 decreases – the CTC also decreases. Conversely, when market prices decline, and  
9 stranded cost increases, the CTC increases.

10 Q. GIVEN THAT THE CTC MOVES INVERSELY WITH RESPECT TO MARKET  
11 PRICES, WHY ISN'T THAT SUFFICIENT TO PROTECT CUSTOMERS AGAINST  
12 OVER-COLLECTION OF STRANDED COST? WHY IS IT ALSO NECESSARY FOR  
13 THE REGULATORY ASSET CHARGE TO MOVE INVERSELY WITH MARKET  
14 PRICES?

15 A. As long as the CTC is greater than zero, the regulatory asset charge can remain fixed  
16 without an over-collection of stranded cost occurring. The loophole in the Settlement  
17 kicks in when market prices are relatively high – specifically, when the MGC is greater  
18 than the generation charge in the APS unbundled tariff. In this case the CTC *should* be  
19 negative; however, the Settlement specifically prohibits a negative CTC from being  
20 applied to a customer's bill. What the Settlement fails to recognize is that, in this  
21 situation, *at least some portion of APS' regulatory assets is no longer a stranded cost*. To  
22 be precise, the *actual* regulatory asset stranded cost is reduced by the amount of the  
23 negative CTC, as this is the amount of regulatory asset charge that APS can recover  
24 through the relatively high market price. Yet the Settlement permits the utility to continue  
25 collecting the full regulatory asset charge as if it were all still stranded. As a result, the  
26

1 utility is allowed to reap an unfair windfall at the expense of the competitive customer,  
2 amounting to an over-recovery of stranded cost.

3 Q. CAN YOU ILLUSTRATE THIS PROBLEM WITH SOME SIMPLE EXAMPLES?

4 A. Yes. I will refer to Exhibit KCH-2 to aid my explanation. Let's start with a case in which  
5 over-recovery of stranded cost does not occur.<sup>5</sup> This case is illustrated as Example A in  
6 the exhibit. Suppose APS has an unbundled generation charge of 4 cents/kWh. Further  
7 suppose that it has a regulatory asset charge of 1 cent/kWh, and that initially, the MGC is  
8 3.5 cents/kWh. Finally, for completeness of illustration (but not really affecting the  
9 results), also assume that the utility has unbundled delivery charges (transmission,  
10 distribution, system benefits, etc.) totaling 3.5 cents/kWh. The sum of unbundled APS  
11 charges, then, is the 4-cent generation charge plus the 1-cent regulatory asset charge plus  
12 the 3.5-cent delivery charge for a total of 8.5 cents/kWh.

13 Now let's examine the stranded cost situation. According to the net revenues lost  
14 method, stranded cost is equal to the APS generation and regulatory asset costs that can  
15 not be recovered at the market price. In Example A, this amount is equal to the 4-cent  
16 generation charge plus the 1-cent regulatory asset charge minus the 3.5-cent MGC, for a  
17 stranded cost of 1.5 cents/kWh. Recall that the utility collects this stranded cost via two  
18 components: the regulatory asset charge and the CTC. Since the CTC (on a per-kWh  
19 basis) is the difference between the APS generation charge (4 cents/kWh) and the MGC  
20 (3.5 cents/kWh), it is equal to 0.5 cent/kWh. When added to the regulatory asset charge  
21 of 1 cent/kWh, the total stranded cost collected is 1.5 cents/kWh; thus, in Example A, the  
22 stranded cost *collected* is equal to the stranded cost *actually incurred*.

23  
24 <sup>5</sup> For purposes of this discussion, I will assume that the calculation of stranded cost adopted in the APS Settlement is  
25 valid. My purpose in doing so is to demonstrate that even if one accepts the stranded cost calculation method in the  
26 Settlement, an over-recovery of stranded cost is very likely due to the regulatory asset loophole. I am not waiving  
the *separate* argument that the stranded cost calculation in the Settlement is itself invalid because it overstates the  
magnitude of stranded cost in the first place.

1 Q. PLEASE CONTRAST THIS CASE WITH ONE IN WHICH OVER COLLECTION OF  
2 STRANDED COST OCCURS.

3 A. The case of over-collection of stranded cost is illustrated in Example B. In this case, all  
4 the assumptions are identical to Example A, except the market price of power is higher,  
5 such that the MGC is equal to 4.5 cents/kWh. The actual stranded cost *incurred* is the 4-  
6 cent generation charge plus the 1-cent regulatory asset charge minus the 4.5-cent MGC,  
7 for a stranded cost of 0.5 cent/kWh. But look at how much stranded cost is *collected*. In  
8 this case, the CTC *should* be a negative value, -0.5 cent/kWh, because the MGC is 0.5  
9 cent *greater* than the APS generation charge. Recall, though, that the Settlement  
10 prohibits a negative CTC; thus, the CTC paid by the customer is set at zero. At the same  
11 time, the other component of the stranded cost charge – the regulatory asset charge –  
12 remains fixed at 1 cent/kWh. Thus, the customer is forced to pay a stranded cost charge  
13 of 1 cent/kWh, even though the utility is incurring a stranded cost of only 0.5 cent/kWh.  
14 This situation is very clearly an over-collection of stranded cost.

15 *The Settlement must be modified to prevent this over-collection of stranded cost*  
16 *from occurring. Failure to correct this problem will result in competitive customers*  
17 *paying APS more than 100 percent of its stranded cost, to the detriment of both*  
18 *customers and the implementation of competition.*

19 Q. HOW CAN THE SETTLEMENT BE AMENDED TO REMEDY THIS PROBLEM?

20 A. The problem can be remedied by inserting the following sentence after the second-to-last  
21 line of the second paragraph of Section II, "Unbundled Rates":

22 "If the resulting value is negative, the customer's regulatory asset charge will be reduced  
23 by the amount of the negative CTC."

24 In addition, in Exhibit A, in the section addressing the "Monthly Customer  
25 Transition Charge Calculation," the following sentence should be *deleted*:  
26

1 "The monthly CTC cannot be less than zero."

2 The deleted sentence should be replaced by the statement:

3 "If the monthly CTC is less than zero, the customer's regulatory asset charge will be  
4 reduced by the amount of the negative monthly CTC."

5 Q. DOESN'T THE STAFF TESTIMONY INDICATE THAT THE CTC CAN BE  
6 NEGATIVE?

7 A. The Staff testimony on this question is very confusing. In responding to the question,  
8 "Could the CTC be negative?" Staff witness Lee Smith makes the following statement:

9 "In the summer months, when the NYMEX spot prices are high, it is quite likely  
10 that the [CTC] might be negative. If [APS] does not want to show a negative CTC  
11 on customer bills, this amount could be credited to customers in future months."  
[Smith direct, p. 7]

12 There are four things about Ms. Smith's statement I find confusing. First, the  
13 general premise of her response – that the CTC may be negative and credited to  
14 customers – directly contradicts Exhibit A of the Settlement, which plainly states, "The  
15 monthly CTC cannot be less than zero."

16 Second, I do not understand the basis of the phrase: "...if [APS] does not *want* to  
17 show a negative CTC on customer bills..." I do not see why the utility should have any  
18 discretion in this matter at all. If, despite the prohibition in Exhibit A, the Settlement  
19 allows a negative CTC as Ms. Smith is suggesting, then a negative value should be  
20 "shown" and "billed" to the customer. It should not matter whether the utility *wants* to  
21 do this or not.

22 Third, I do not understand the basis of the suggestion that the negative CTC *could*  
23 be credited to customers in future months. Credited by whom? APS? Again, I do not see  
24 why such crediting should be a matter of utility discretion. Either the crediting to  
25 customers of negative CTC is required or it is not. If it is not required, then I do not  
26 expect that APS is going to voluntarily provide it.

1 Fourth, even if all the ambiguity I have just described were resolved, Ms. Smith's  
2 statement that negative CTC could be credited to *customers* in future months is vague  
3 regarding both the crediting mechanism and the identity of the customers being credited.  
4 If the crediting mechanism Ms. Smith is describing is one in which the cumulative  
5 negative CTC is: (1) taken from the *individual* customers who should have been given  
6 this credit on their bills in the first place, and (2) then somehow pooled in the form of a  
7 future *aggregate* CTC reduction, then I wish to register a strong objection. Such an  
8 approach would be fraught with cross-subsidization. Even more troubling, the over-  
9 collection of stranded cost at the individual customer level would be largely uncorrected  
10 by such an approach, resulting in a stifling of competitive choice, and ensuring a failure  
11 of the Commission's competition plan at the individual customer level.

12 In conclusion, Staff's discussion of the negative CTC issue provides little comfort  
13 for customers and raises more questions than it answers. The sure solution to the problem  
14 of potential over-collection of stranded cost is to adopt the amendments I am  
15 recommending.

16 Q. IS THE OVER-COLLECTION LOOPHOLE PRESENT IN THE TEP SETTLEMENT  
17 AS WELL?

18 A. The TEP Unbundled Tariff does not include a separate cost component for regulatory  
19 assets nor have I found any restrictions against a negative transition charge in the TEP  
20 Settlement. Therefore, this loophole does not appear to be a problem in the TEP  
21 Settlement.

22 **TEP Transmission Purchase and CTC Increases**

23 Q. YOU STATE THAT THE TEP SETTLEMENT NEEDS TO BE MODIFIED TO  
24 ENSURE THAT ANY USE OF FUNDS TO PURCHASE TRANSMISSION  
25  
26

1 FACILITIES DOES NOT CAUSE THE COMPETITION TRANSITION CHARGE  
2 (CTC) PAID BY TEP CUSTOMERS TO INCREASE. PLEASE EXPLAIN.

3 A. Certain TEP generation assets are likely to sell at prices greater than their net book value.  
4 The Commission's Stranded Cost Order makes it very clear that the proceeds from such a  
5 sale must be used to reduce the net stranded cost burden to customers.<sup>6</sup> However, the TEP  
6 Settlement allows TEP to divert a portion of such proceeds to purchase transmission  
7 assets. Specifically, the TEP Settlement allows any gain on a generation asset sale over  
8 net book value may be used to capitalize the acquisition of transmission assets (termed  
9 "Capitalized Balance"), in an amount up to 35 percent of the net book value of any  
10 transmission assets that TEP purchases from APS, SRP, AEPCO, or any others approved  
11 by the Commission.<sup>7</sup>

12 Thus, proceeds which should be used for keeping the CTC as low as possible are  
13 to be diverted in order to capitalize TEP's transmission acquisitions. I am concerned that  
14 such a change in the use of such proceeds will result in higher stranded cost charges for  
15 TEP customers.

16 Q. DOES THE TEP SETTLEMENT ATTEMPT TO PROVIDE PROTECTIONS  
17 AGAINST INCREASES IN STRANDED COSTS THAT MIGHT RESULT FROM  
18 TEP'S USE OF GENERATION PROCEEDS TO PURCHASE TRANSMISSION  
19 ASSETS?

20 A. Yes, the Settlement makes such an attempt, but it only remedies *part* of the stranded cost  
21 increase that will result from TEP's purchase of transmission assets.

22  
23 <sup>6</sup> Arizona Corporation Commission, Decision No. 60977, p. 12. An Affected Utility that divests its generation is  
24 entitled to retain 50 percent of negative stranded costs *as defined by the Competition Rules*. According to the  
25 Competition Rules, stranded cost is clearly a *net* figure that is calculated with respect to *all* assets, i.e., assets with  
26 net book values lower than their market values are netted against assets with net book values greater than their  
market values. The net result is stranded cost. [R14-2-1604.38] For negative stranded cost to result, then, the *entire*  
calculation must be negative. Therefore, unless the entire calculation is negative, all proceeds from the asset sale  
must be dedicated to reducing stranded costs.

<sup>7</sup> TEP Settlement, Section VI.

1 Q. PLEASE EXPLAIN.

2 A. The TEP Settlement contains the following statement:

3 "It is the parties' intention to provide TEP with an opportunity to utilize the Capitalized  
4 Balance in the Transco without increasing the stranded cost to TEP's customers. In  
5 exchange TEP's jurisdictional rates will be reduced by an amount equal to the return on  
6 the Capitalized Balance, calculated using the CTC after-tax weighted average cost of  
7 capital for the term of any CTC recovery. Thereafter, TEP's rates will be reduced to  
8 reflect the recovery of the common equity balance over a ten year period on a straight-  
9 line basis."<sup>8</sup>

10 According to this statement, part of TEP's equity return on its newly-acquired  
11 transmission assets will be used to reduce its Commission-regulated rates. However, at  
12 the same time, the amount of stranded costs to be recovered will be higher by the amount  
13 of the proceeds diverted to the transmission purchase. This higher stranded cost level will  
14 result in: (1) higher stranded cost carrying costs and (2) higher stranded cost amortization  
15 charges for customers. The reduction of Commission-regulated rates described in the  
16 Settlement (above) appears to be designed only to offset the increased *carrying cost* on  
17 the unamortized stranded cost balance. The higher stranded cost *amortization* charges  
18 will still be borne by customers. According to the Settlement, TEP does not return the  
19 higher stranded cost principle to customers until after the CTC has been recovered, and  
20 even then it will take another ten years.

21 In summary, the Settlement allows TEP to divert certain proceeds from generation  
22 asset sales to capitalize TEP's transmission acquisitions. Consequently, stranded costs are  
23 higher. TEP will use part of its equity return on the transmission assets to offset the  
24 increased *carrying cost* on the unamortized stranded cost balance, but customers are still  
25

26 <sup>8</sup> TEP Settlement, Section VI.

1 faced with higher stranded cost *amortization* charges. The bottom line is that stranded  
2 costs charges to customers are higher during the CTC recovery period. The Settlement  
3 does not succeed in protecting customers from this harmful consequence.

4 Q. CAN YOU PROVIDE A SIMPLE EXAMPLE TO ILLUSTRATE YOUR POINT?

5 A. Yes. If the net book value of generation assets sold were \$1 billion and the net purchase  
6 price of the assets were \$600 million, then stranded costs would be \$400 million. This  
7 stranded cost would be paid off by customers over time through the CTC. Each year the  
8 CTC payment would include an amortization charge to pay down the principle, and it  
9 would also include a charge to cover carrying costs on the unamortized balance. If, as  
10 allowed in the Settlement, TEP were to divert \$50 million in asset sale proceeds to  
11 capitalize its purchase of transmission, the stranded cost total would be increased by this  
12 \$50 million to \$450 million. The Settlement contemplates a partial offset by using the  
13 equity return on the newly-acquired transmission assets to compensate customers for the  
14 increased carrying costs caused by the \$50 million increase in stranded cost. However,  
15 customers would still face amortization charges associated with \$450 million in stranded  
16 cost, as compared to \$400 million absent the transmission purchase. Consequently, the  
17 CTC is still higher than it would have been absent the transmission purchase.

18 Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS  
19 MATTER?

20 A. The Commission should not allow TEP to use any proceeds from generation assets sales  
21 to purchase transmission assets if such use of proceeds would prevent customers from  
22 realizing the lowest possible stranded cost charges. The burden should be on TEP to  
23 demonstrate that it can acquire transmission without causing the CTC to be higher than  
24 the level that obtains when all proceeds are used to reduce stranded cost. Until such a  
25  
26

1 convincing demonstration can be made, the Commission should prohibit TEP from using  
2 any of the proceeds from generation asset sales for acquiring transmission.

3 **Additional customer protection for declaring a failed auction in the TEP divestiture plan**

4 Q. WHAT ADDITIONAL CUSTOMER PROTECTIONS NEED TO BE ADDED TO THE  
5 CRITERIA FOR DECLARING A FAILED AUCTION IN THE TEP DIVESTITURE  
6 PLAN?

7 A. The TEP divestiture should only proceed if it will make customers better off. The  
8 measurement test of whether this occurs is that the market price of power plus delivery  
9 charges (distribution, transmission, ancillary services, system benefits charge) plus  
10 regulatory asset charges plus the CTC should be less than the bundled price of power paid  
11 by customers under regulated rates. The cost component being determined under the  
12 divestiture plan is the CTC, which is derived by subtracting the assets sales prices from  
13 their regulated cost basis, e.g., net book value. Because the sales price is unknown in  
14 advance of the asset auction, the CTC is also unknown. To provide assurance that the  
15 divestiture will make customers better off, it is essential that the Commission require that  
16 any asset sale be accompanied by a set of minimum bid requirements. The minimum  
17 bids should be calculated to ensure that the resultant CTC passes the measurement test of  
18 making customers better off.

19 The TEP Settlement already has a provision giving the Commission the authority  
20 to declare a failed auction if the Commission determines that bids are not representative  
21 of an asset's market value.<sup>9</sup> I recommend that the criteria for declaring a failed auction be  
22 extended to include a requirement that a failed auction be declared if bids result in a CTC  
23 that makes customers worse off than they would be under existing regulated rates.

24 **Treatment of "stipulated loss values" in the TEP divestiture plan**

25  
26 <sup>9</sup> TEP Settlement, Section VII, Part 1.

1 Q. WHAT CUSTOMER PROTECTIONS ARE NECESSARY REGARDING THE  
2 TREATMENT OF "STIPULATED LOSS VALUES" IN THE TEP DIVESTITURE  
3 PLAN?

4 A. The Stranded Cost Recovery Plan that TEP has previously filed with the Commission  
5 discusses certain "stipulated loss values" associated with TEP leases of generation  
6 facilities.<sup>10</sup> Stipulated loss values refer to payments TEP is contractually obligated to  
7 make to the leaseholders in the event of early termination. TEP indicates that the total  
8 payable as of January 1, 2001 is approximately \$1.2 billion. Yet, according to Schedule 5  
9 of TEP's Stranded Cost Recovery Plan filing, these leased assets have an aggregate net  
10 book value of only \$651 million. In fact, the original cost of the assets was \$718 million  
11 – about half a billion dollars less than the stipulated loss values.

12 The TEP Settlement appears to be silent on the appropriate treatment of these  
13 leased facilities, even though they have termination payments nearly double their net  
14 book values. Protection for customers is essential should any sale of these assets be  
15 contemplated. Clearly, payment of the stipulated loss values would represent tremendous  
16 windfall gains to the leaseholders, and customers should not be stuck with the tab.  
17 Stipulated loss values in excess of net book value should not be included in the CTC.

18 The TEP Settlement or any TEP divestiture plan should not be approved until a  
19 plan is developed that will protect customers from the "stipulated loss value" penalties  
20 contained in various TEP generation leases.

21 **Treatment of fixed Must-run generation costs**

22 Q. YOU INDICATED THAT THE APS AND TEP SETTLEMENTS NEED TO BE  
23 MODIFIED TO REQUIRE AN UNBUNDLED, MUST-RUN FIXED-COST CHARGE  
24  
25

26 <sup>10</sup> TEP Stranded Cost Recovery Plan, August 21, 1998, pp. 11-12.

1 THAT WILL SERVE AS A CREDIT AGAINST THE RETAIL ACCESS  
2 CUSTOMER'S BILL. PLEASE EXPLAIN.

3 A. Currently, the fixed costs associated with APS and TEP generation facilities that will  
4 provide Must-run generation service are included in bundled rates. However, in  
5 accordance with the Must-run protocol developed by stakeholders in the AISA Operating  
6 Committee, and adopted by the AISA Board for submittal to FERC, fixed Must-run costs  
7 are to be billed to Scheduling Coordinators in accordance with their relative share of  
8 monthly load in a given Must-run Zone. This proposal was made to the AISA Operating  
9 Committee by APS. However, neither the APS Settlement nor the TEP Settlement  
10 incorporates this pricing design. Therefore, the Settlements must be modified to make  
11 them compatible with the treatment of fixed Must-run costs being proposed to the FERC  
12 by the AISA.

13 Q. HOW DO THE APS AND TEP SETTLEMENTS NEED TO BE MODIFIED TO MAKE  
14 THEM COMPATIBLE WITH THE TREATMENT OF FIXED MUST-RUN COSTS  
15 BEING PROPOSED TO THE FERC BY THE AISA?

16 A. The fixed Must-run costs that are to be billed to Scheduling Coordinators must be  
17 included as a separate line item in each unbundled tariff. Customers residing in the Must-  
18 run Zone who purchase competitive power would not be billed for this service so long as  
19 the cost was being billed to the customer's Scheduling Coordinator, as planned.  
20 Customers who purchase competitive power and who do not reside in a Must-run Zone  
21 would not be billed for this service at all. Failure to make these changes will result in the  
22 utilities double-billing parties for fixed Must-run costs.

23 **Treatment of variable Must-run generation costs**

24 Q. YOU INDICATED THAT THE APS AND TEP SETTLEMENTS NEED TO BE  
25 MODIFIED TO REQUIRE AN ADJUSTMENT TO THE MARKET GENERATION  
26

1 CREDIT TO ACCOUNT FOR THE INCIDENCE OF MUST-RUN VARIABLE COST  
2 CHARGES THAT ARE LEVIED ON SCHEDULING COORDINATORS. PLEASE  
3 EXPLAIN.

4 A. Currently, the variable costs associated with APS and TEP generation facilities that will  
5 provide Must-run generation service are included in bundled rates. However, in  
6 accordance with the Must-run protocol developed by stakeholders in the AISA Operating  
7 Committee, and adopted by the AISA Board for submittal to FERC, variable Must-run  
8 costs are to be billed to each Scheduling Coordinator based on the amount of Must-run  
9 generation purchased by that Scheduling Coordinator from the Must-run provider (in this  
10 case, APS and TEP).

11 These variable Must-run charges are to be billed at the respective Must-run  
12 facilities' actual variable costs. It is likely that the variable costs associated with Must-run  
13 facilities will generally be greater than the Palo Verde market prices used in calculating  
14 the MGC for APS and TEP. Unless the cost differential between the variable cost of the  
15 Must-run facilities and the Palo Verde market price is incorporated into the calculation of  
16 the MGC, the utilities will double-collect this cost differential from competitive  
17 customers. This double-collection will occur because this cost differential is already  
18 recovered once in the utilities' tariffs and it will be recovered again as variable Must-run  
19 costs are billed to Scheduling Coordinators (while the corresponding MGC is based on  
20 the presumably lower Palo Verde price).

21 Q. HOW DO THE APS AND TEP SETTLEMENTS NEED TO BE MODIFIED TO MAKE  
22 THEM COMPATIBLE WITH THE TREATMENT OF VARIABLE MUST-RUN  
23 COSTS BEING PROPOSED TO THE FERC BY THE AISA?

24 A. In any MGC calculation period, the MGC calculation should account for the share of load  
25 served being by Must-run generation in a given Must-run zone. Thus, the market price  
26

1 component of the MGC should be a weighted average of the relevant market price index  
2 (e.g., Palo Verde) and the Must-run variable cost charges that are levied on Scheduling  
3 Coordinators in that particular Must-run zone. So, for example, if 5 percent of the load in  
4 a Must-run zone in a given hour is served by Must-run generation, then the MGC for that  
5 particular hour should be calculated using a 95 percent weight for the market index price  
6 and a 5 percent weight for the average Must-run variable cost charges levied on  
7 Scheduling Coordinators in that hour.<sup>11</sup>

8 Q. IS THIS ADJUSTMENT LIKELY TO RESULT IN A SIGNIFICANT IMPACT ON  
9 THE MGC?

10 A. For a Must-run zone in which the Must-run variable costs are close to market prices, or  
11 alternatively, the number of Must-run hours are relatively few, there is likely to be little  
12 noticeable effect from this adjustment. Such is likely to be the case for APS' Phoenix  
13 Must-run zone. On the other hand, Tucson experiences many more Must-run hours. I  
14 believe this adjustment is very important for protecting Tucson customers from paying  
15 twice for the Must-run variable cost differential.

16 **Distribution charges differentiated by voltage level**

17 Q. YOU RECOMMEND THAT, FOR CUSTOMERS TAKING EXTRA LARGE DIRECT  
18 ACCESS GENERAL SERVICE, THE APS UNBUNDLED TARIFF SHOULD BE  
19 MODIFIED TO PROVIDE DISTRIBUTION CHARGES THAT ARE  
20 DIFFERENTIATED ACCORDING TO THE VOLTAGE LEVEL AT WHICH  
21 SERVICE IS TAKEN. PLEASE EXPLAIN.

22 A. The proposed APS unbundled tariff for Extra Large customers provides a single "vanilla"  
23 distribution charge. However, large industrial customers may take service at a wide range  
24

25 <sup>11</sup> An equivalent adjustment would be to assign to 5 percent of each competitive customer's kWh in that hour a  
26 MGC calculated using the variable Must-run cost, and to assign to 95 percent of the customer's kWh the MGC  
calculated using the market price index.

1 of voltage levels. In keeping with principles of cost causality, customers taking service at  
2 higher levels of voltage should not be allocated the costs of the lower-voltage portion of  
3 the system. The APS unbundled tariff for Extra Large customers should be modified to  
4 reflect the differences in distribution system cost attributable to customers based on the  
5 voltage levels at which they take service.

6 **Spreading the scheduled APS rate reductions across the various unbundled services**

7 Q. YOU RECOMMEND THAT THE ONE PERCENT RATE REDUCTIONS  
8 SCHEDULED FOR 1999 AND 2000 IN THE APS SETTLEMENT SHOULD BE  
9 SPREAD ACROSS ALL UNBUNDLED SERVICES TO THE GREATEST EXTENT  
10 POSSIBLE, INSTEAD OF BEING LIMITED TO GENERATION SERVICE. PLEASE  
11 EXPLAIN.

12 A. The intent of these price reductions is that they be experienced by *all* customers. To the  
13 extent that all of the reduction is applied to the APS generation charge, the benefit of this  
14 reduction to competitive customers will only be temporary, as the price reduction will  
15 expire when the CTC is eliminated.<sup>12</sup> On the other hand, to the extent that the price  
16 reduction is spread to the other unbundled services – such as distribution – the price  
17 reduction will be permanent for all customers. I recommend that the Commission modify  
18 the APS Settlement to make the rate reductions scheduled for 1999 and 2000 applicable  
19 to all unbundled services, to the greatest extent possible.

20 **Appropriate basis for calculating the CTC**

21 Q. PLEASE EXPLAIN YOUR RECOMMENDATIONS REGARDING THE  
22 APPROPRIATE COST BASIS FOR CALCULATING THE CTC.  
23

24  
25 <sup>12</sup> The only way in which a competitive customer will realize the rate reduction is through a reduction in the CTC.  
26 Note also that because the APS Settlement prohibits the CTC from being negative, competitive customers will also  
be deprived the benefits of the rate reduction during periods when the CTC is set at zero when it would otherwise be  
negative.

1 A. In the case of customers currently purchasing tariff service, it is critical that the cost basis  
2 used for calculating their CTC be that of their current rate schedule – and that these  
3 customers *not* be forced onto a higher-cost unbundled tariff in order to obtain access to  
4 the competitive market. In other words, the Commission must be very wary of any  
5 attempts by the Affected Utilities to “collapse” the number of rate schedules applicable  
6 for retail access into something smaller than the number of rate schedules offered for  
7 bundled service. In such a scenario, some customers will be on bundled tariffs for which  
8 there is no unbundled counterpart. In order to obtain access to retail competition, these  
9 customers would be required to take service under a different rate schedule – quite  
10 possibly a rate schedule with a higher cost basis. If so, the customer would be forced to  
11 pay a CTC that is based on a higher-cost tariff than the one they are currently on, and  
12 would thereby be forced to make a greater contribution to the utility’s stranded cost than  
13 the customer makes under current rates. Such a situation would violate the proportionality  
14 clause in the Competition Rule, which requires that stranded cost be recovered in  
15 substantially the same proportion as these costs are now recovered from customers or  
16 customer classes under current rates.<sup>13</sup> Needless to say, such a situation would also  
17 create a serious barrier to competition for these customers.

18 Q. ARE YOU AWARE OF ANY ATTEMPTS BY AFFECTED UTILITIES TO  
19 “COLLAPSE” THE NUMBER OF TARIFFS AND THEREBY FORCE CUSTOMERS  
20 ONTO HIGHER-COST TARIFFS IN ORDER TO GAIN ACCESS TO THE  
21 COMPETITIVE MARKET?

22 A. It appears that APS is proposing exactly that. In its Direct Access Tariff filing of  
23 February 13, 1998, APS filed an unbundled tariff corresponding to every bundled tariff.  
24 In the Settlement, however, APS’ unbundled tariff is collapsed into just four rate  
25

26 <sup>13</sup> Arizona Corporation Commission, Competition Rules, R14-2-1607(G).

1 schedules. Consequently, many customers will have to move to an Unbundled Tariff with  
2 a different cost basis than their current rate schedule in order to take retail access. To  
3 take just one example, APS offers no unbundled version of its E-35 tariff. Therefore, E-  
4 35 customers who wish to participate in retail access will presumably have to do so under  
5 the unbundled version of the E-34 tariff. However, such a switch is apt to cost customers  
6 hundreds of thousands of dollars in increased costs, effected through the CTC. Obviously,  
7 customers in this situation are precluded from meaningful participation in the competitive  
8 market. APS' proposed "collapsing" of the number of unbundled tariffs creates a  
9 situation ripe for abuse and additional obstacles to competition. The Commission should  
10 order APS to file unbundled tariffs corresponding to each of its bundled tariffs.

11 Q. YOU INDICATE THAT THE USE OF AN APPROPRIATE COST BASIS FOR  
12 CALCULATING THE CTC IS ALSO IMPORTANT FOR SPECIAL CONTRACT  
13 CUSTOMERS. PLEASE EXPLAIN.

14 A. If competition is to be fair and effective, it is essential that the CTC for a special contract  
15 customer be based on the effective rate that customer now pays in their contract. The  
16 CTC so calculated would then apply for special contract customers who wish to  
17 participate in the retail competitive market after their contracts expire. I believe the  
18 necessary protections for special contract customers are already in the Competition Rule  
19 and the Commission's previous Stranded Cost Order; however, neither the APS nor the  
20 TEP unbundled filings contain the necessary CTC adjustments for special contract  
21 customers. I am urging the Commission to be vigilant in requiring APS and TEP to  
22 modify their unbundled tariffs to comply with the proportionality clause in the  
23 Competition Rule and the "Hold Harmless" provision in the previous Stranded Cost  
24 Order, as these provisions apply to special contract customers.<sup>14</sup>

25  
26 <sup>14</sup> For the proportionality clause, see Competition Rules, R14-2-1607(G). For the "Hold Harmless" provision, see  
Decision No. 60977, p. 18, which is discussed below in my testimony.

1 Q. CAN YOU ELABORATE ON THE NEED FOR THESE MODIFICATIONS?

2 A. Yes. If, in order to gain access to the competitive market, special contract customers were  
3 forced to pay CTCs based on tariffs more expensive than their current contracts, the  
4 Competition Rule and the Stranded Cost Order would be violated. In such a  
5 circumstance, these customers would be over-charged for stranded costs, because they  
6 would be assigned stranded costs that are not included in their current rates. Such an  
7 over-collection of stranded cost would violate the principle in the Competition Rule that  
8 requires stranded cost to be recovered in substantially the same proportion as these costs  
9 are now recovered from customers or customer classes under current rates.<sup>15</sup> It would  
10 also violate the provision in the Stranded Cost Order in which the Commission expressly  
11 limits the CTC such that *no customer will receive a rate increase as a result of stranded*  
12 *costs.*<sup>16</sup>

13 Q. WHAT WOULD BE THE POLICY IMPLICATIONS OF FAILING TO BASE THE  
14 CTC FOR SPECIAL CONTRACT CUSTOMERS ON THE EFFECTIVE RATES  
15 THESE CUSTOMERS NOW PAY IN THEIR CONTRACTS?

16 A. The Arizona retail competition program would turn out to be a disaster for Arizona's  
17 largest industrial customers. These customers would all face substantial increases in the  
18 price of electricity – due not to market prices, but due to the windfall increase in stranded  
19 cost payments reaped by the utilities. This stranded cost windfall would consist of  
20 stranded cost payments that are well beyond the contributions to stranded cost these  
21 customers are now making under current rates. As a matter of policy, the Commission  
22 would have gone through a great deal of well-intended effort to introduce competition to  
23 benefit *all* Arizona customers – only to have that objective negated – indeed reversed,  
24 due to failure to implement retail competition correctly. Saddling the largest users of  
25

26 <sup>15</sup> Competition Rules, R14-2-1607(G).

<sup>16</sup> Decision No. 60977, p. 18.

1 electricity in Arizona with significant price increases as a result of the competition  
2 program would amount to an abject failure in policy, with serious negative consequences  
3 for important sectors of the Arizona economy.

4 Q. WHAT MODIFICATION IS NECESSARY TO REMEDY THIS PROBLEM?

5 A. The remedy is simple. The Commission should adopt the following language as part of  
6 any Order authorizing stranded cost recovery:

7  
8 "For special contract customers who, upon the expiration of their  
9 contracts, purchase competitive power, the CTC will be the residual after  
10 subtracting distribution, transmission, metering, billing, fixed Must-run,<sup>17</sup>  
11 system benefits, the regulatory asset charge, and the retail MGC of the  
unbundled tariff that is most applicable to the customer from the  
customer's current special contract rate. The remaining unbundled pricing  
components for these customers will be equal to those in the tariff that is  
otherwise applicable."

12 Q. DOES YOUR RECOMMENDATION EXTEND THE TERMS OF THE SPECIAL  
13 CONTRACT BEYOND THE EXPIRATION DATE?

14 A. Nothing in my recommendation creates any obligation on the utility to extend its special  
15 contract. However, when a special contract expires and a customer enters the competitive  
16 market, it is the *utility* that is seeking to extend the customer's obligations beyond the  
17 contract term by demanding a stranded cost payment. The relevant question then becomes  
18 one of determining what obligation, if any, this customer has to subsidize the utility's  
19 uneconomic costs beyond the term of the contract. The Commission has already put  
20 boundaries on the answer: *No more than the customer pays under current rates*. Thus,  
21 the special contract rate is carried forward only to the extent of defining the utility's  
22 ability to extract a subsidy from this customer after the customer's contract expires.

23 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

24 A. Yes, it does.

25  
26 <sup>17</sup> As noted previously, Fixed Must-run is not included as a separate unbundled service in the APS and TEP  
unbundled tariffs, but needs to be.

**KEVIN C. HIGGINS**  
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**(801) 355-4365**

**Vitae**

**PROFESSIONAL EXPERIENCE**

Senior Associate, Energy Strategies, Inc., Salt Lake City, Utah, February 1995 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over \$300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic

analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

## **EDUCATION**

Ph.D. Candidate, Economics, University of Utah (coursework and exams completed, 1981).

Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

## **SCHOLARSHIPS AND FELLOWSHIPS**

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.

Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.

Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.

New York State Regents Scholar, 1972 to 1976.

## **EXPERT TESTIMONY**

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," Utah Public Service Commission, Case No. 80-999-06, pp. 1293-1318.

Prefiled testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs); cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for

levelized contracts) and December 16-17, 1986 (avoided costs).

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," Utah Public Service Commission, Case No. 84-999-20. Prefiled direct testimony submitted June 17, 1985. Prefiled rebuttal testimony submitted July 29, 1985; Cross-examined August 19, 1985.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," Utah Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986; cross-examined July 17, 1986.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," Utah Public Service Commission, Case No. 86-035-13; prefled direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"Cogeneration: Small Power Production," Federal Energy Regulatory Commission, Docket No. RM87-12-000. Statement delivered March 27, 1987, on behalf of State of Utah, in San Francisco.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," Utah Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," Utah Public Service Commission, Case No. 86-057-07. Prefiled direct testimony submitted January 15, 1988; cross-examined March 30, 1988.

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," Utah Public Service Commission, Case No. 87-035-27; prefled direct testimony submitted April 11, 1988; cross-examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," Utah Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989; cross-examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," Utah Public Service Commission, Case No. 89-057-15. Pre-filed direct

testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," Utah Public Service Commission, Case No. 95-057-02. Prefiled direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 1995.

"Questar Pipeline Company," Federal Energy Regulatory Commission, Docket No. RP95-407. Direct testimony prepared, but withheld subject to settlement. Settlement approved July 1, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," Wyoming Public Service Commission, Docket No. 2000-ER-95-99. Prefiled direct testimony submitted April 8, 1996.

"In the Matter of Arizona Public Service Company's Rate Reduction Agreement," Arizona Corporation Commission, Docket No. U-1345-95-491. Direct testimony prepared, but withheld consequent to issue resolution. Agreement approved April 18, 1996.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," Utah Public Service Commission, Docket No. 96-2018-01. Prefiled direct testimony submitted July 8, 1996.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," New York Public Service Commission, Case 96-E-0897. Testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Arizona Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Cross-examined February 25, 1998.

"Hearings on Customer Choice," Salt River Project Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"Hearings on Pricing," Salt River Project Board of Directors, written and oral comments provided November 9, 1998.

## **OTHER RELATED ACTIVITY**

Board Member, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance April 1997 to present.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to present.

Consultant to business customers, "In the Matter of Competition in the Provision of Electric Services Throughout the State of Arizona," Arizona Corporation Commission, Docket No. U-0000-94-165. Preparation of comments and participation in staff workshops. Rule on retail electric competition adopted December 23, 1996.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an \$85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

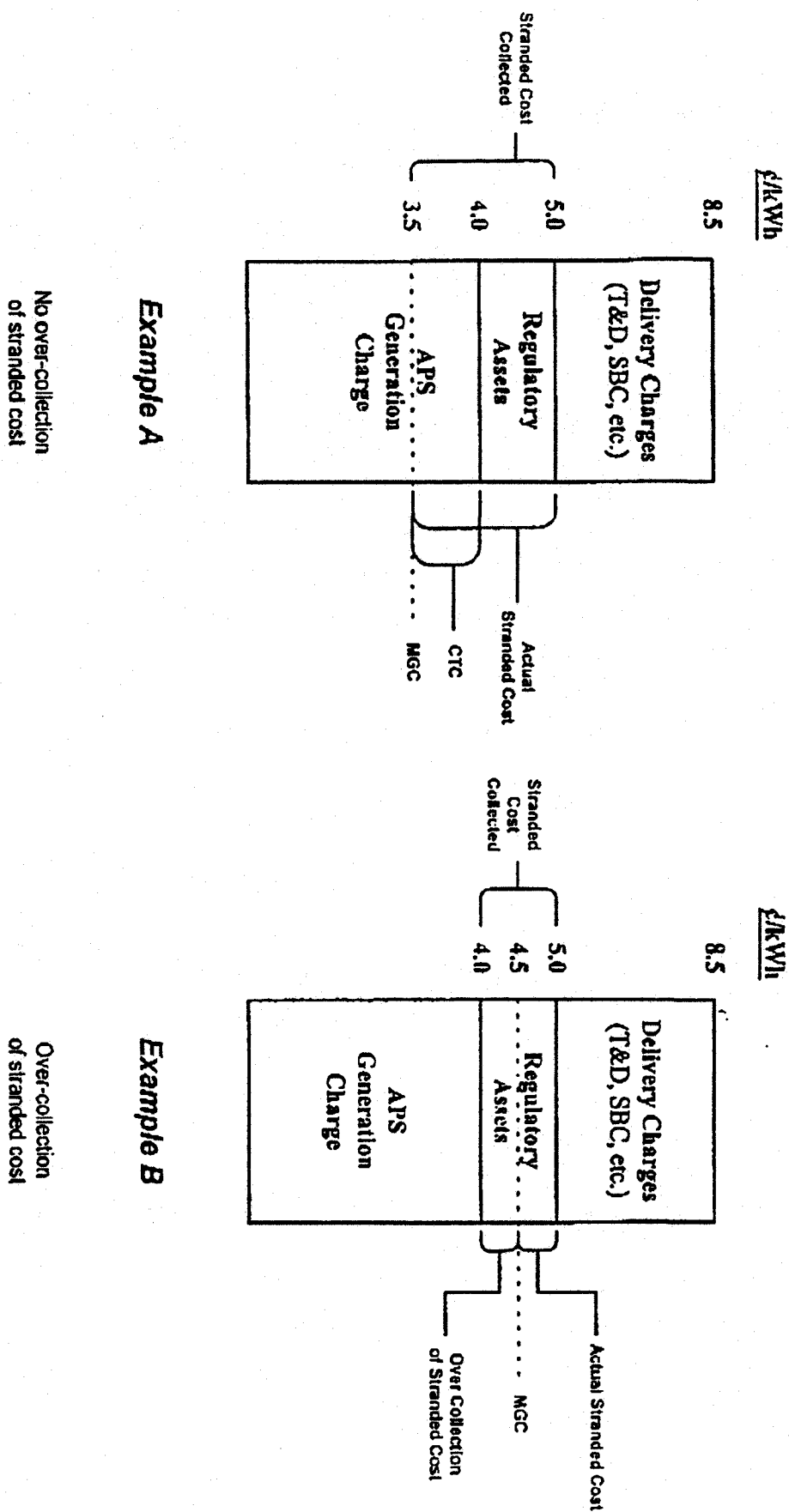
Chairman, Load Management and Energy Conservation Task Force, Utah Public Service

Commission, August 1985 to December 1990.

Alternate delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

# Illustration of Stranded Cost Over-collection Under the Settlement



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AZ CORP COMMISSION

BEFORE THE ARIZONA CORPORATION COMMISSION

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JIM IRVIN

Commissioner - Chairman

RENZ D. JENNINGS

Commissioner

CARL J. KUNASEK

Commissioner

DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION  
OF TUCSON ELECTRIC POWER  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01933A-98-0471

IN THE MATTER OF THE FILING OF  
TUCSON ELECTRIC POWER COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01933A-97-0772

IN THE MATTER OF THE APPLICATION  
OF ARIZONA PUBLIC SERVICE  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01345A-98-0473

IN THE MATTER OF THE FILING OF  
ARIZONA PUBLIC SERVICE COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN  
THE PROVISION OF ELECTRIC SERVICES  
THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

DIRECT TESTIMONY OF DR. ALAN ROSENBERG

On Behalf of Cyprus Climax Metals Company,  
ASARCO Incorporated and Arizonans for  
Electric Choice and Competition

1 Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A My name is Alan Rosenberg and my business address is 1215 Fern Ridge Parkway, Suite  
3 208, St. Louis, Missouri 63141-2000.

4 Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

5 A I am a consultant in the field of public utility regulation and a principal in the firm of  
6 Brubaker & Associates, Inc., energy, economic and regulatory consultants.

7 Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

8 A This is summarized in Appendix A to this testimony.

9 Q ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS  
10 PROCEEDING?

11 A I am testifying on behalf of Arizonans for Electric Choice and Competition (AECC)<sup>1</sup>,  
12 ASARCO Incorporated and Cyprus Climax Metals Company.

13 Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

14 A I have been asked to review the proposed Settlement Agreement (Agreement) between  
15 the Staff and Tucson Electric Power Company (TEP). In particular, it was requested that  
16 I focus my attention on: (a) the proposed unbundling of the rates, and; (b) the proposed  
17 method for granting TEP interim recovery of any stranded costs that it may have and for  
18 allowing customers the opportunity to save money by choosing an alternative supplier.  
19 Consequently, my silence on any other aspects of the Agreement should not be  
20 interpreted as assent or approval.

21 Q WHAT IS YOUR RECOMMENDATION?

22  
23 <sup>1</sup> Arizonans for Electric Choice and Competition is a coalition of companies and associations who  
24 support the introduction of competition in the generation of electric power in Arizona. AECC's members  
25 include Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell,  
26 Allied Signal, Cyprus Climax Metals, ASARCO, Phelps Dodge, Homebuilder's Association of Central  
Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association  
of Industries, Arizona Multi-Housing Association, Arizona Rock Products Association, Arizona Restaurant  
Association, Arizona Association of General Contractors, the Arizona Retailers Association and Enron.

1 A I am firmly convinced that if the Agreement as submitted is approved by the  
2 Commission, competition will not get off the ground in Arizona. If competition is to  
3 have any chance of success in Arizona, then several fundamental modifications need to  
4 be made to the Agreement. My findings can be summarized as follows:

- 5 ▶ **Unbundled Rates.** Unbundled rates as set forth in Exhibit A of the Agreement  
6 should be accepted on a provisional basis only. As soon as possible after the  
7 divestiture is completed, or by July 1, 2000 at the latest, a Phase II to this docket  
8 should commence. In Phase II, intervenors may present evidence as to  
9 modifications that should be made to those rates. Phase II would also be used to  
10 determine the Final Stranded Cost Amount (FSCA) based on the results of the  
11 auction, as well as the appropriate recovery period for that FSCA.
- 12 ▶ **Interim Transition Charge.** I recommend that if an Interim Transition Charge  
13 (ITC) be instituted, and it is not clear that one should be, it be set at a level *no*  
14 *greater than is absolutely necessary* to prevent TEP from defaulting on its  
15 financial obligations. I recommend that an explicit CTC be established to collect  
16 approximately 1¢ per kWh times the total annual retail sales. This should produce  
17 approximately \$75 million on an annual basis. This amount should be  
18 apportioned to classes in proportion to the 4 CP allocator as contained in the  
19 December 1997 cost of service study so that explicit CTC's can be developed for  
20 each class.
- 21 ▶ **Final Stranded Cost.** The Commission should declare that in Phase II, the ITC  
22 revenues collected from each class during the interim period will be compared  
23 with the responsibility of that class for the Final Stranded Cost Amount. The  
24 interim period would be defined as the period January 1, 1999 until the effective  
25 date of the tariffs emanating from Phase II. Based on this comparison, any long-  
26 term Competitive Transition Charge (CTC) should be set accordingly.

20 **Recovery of Interim Transition Costs**  
21 **And the Potential for Customer Savings**

22 Q WHAT ARE STRANDED COSTS?

23 A Stranded costs are properly defined as the difference between the book value of a utility's  
24 generation assets and the price those assets could command in a competitive  
25 environment.<sup>2</sup> A more descriptive term for stranded costs is the uneconomic portion of

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26 <sup>2</sup>There may also be stranded costs associated with purchase power contracts, in which case the

1 the utility's embedded cost. Several states refer to these uneconomic costs as either  
2 stranded costs, or alternatively, "transition" costs. Of course, TEP's net stranded costs  
3 will not be known with certainty until the results of TEP's auction are known and can be  
4 analyzed.

5 Q WHAT METHOD DOES THE AGREEMENT PROPOSE FOR GRANTING TEP  
6 *INTERIM* RECOVERY OF STRANDED COSTS?

7 A For interim recovery of stranded costs, the Agreement uses the term "Interim Transition  
8 Charge" or ITC. The ITC is defined as the difference or residual between the Standard  
9 Offer Embedded Cost of Generation (i.e., the component of the current tariff that relates  
10 to the generation function as unbundled) less the Firm Wholesale Market Generation  
11 Credit (MGC). The MGC, in turn, is derived for each class and is defined as a spot  
12 market price projection, adjusted for class losses, plus an adder.

13 Q DOES THE CUSTOMER'S POTENTIAL FOR SAVING MONEY HINGE ON THE  
14 SIZE OF THEIR MGC?

15 A Yes, it does. The MGC acts in effect as a "shopping credit" for customers that choose an  
16 alternate supplier. A customer will shop for an alternative supplier based on whether or  
17 not the supplier's energy price is lower than the MGC. If transition charges were not an  
18 issue, the customer choosing an alternate supplier would avoid the *entire* component of  
19 the bill that is attributable to the service it no longer buys from TEP, not just the MGC  
20 portion. But since transition costs are an issue in this case, customers will receive a credit  
21 not fully reflective of the total unbundled generation cost of TEP.

22 Thus, the customer's opportunity for savings hinges critically on the credit  
23 amount. The customer's savings will be directly proportional to the difference between  
24

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25 stranded cost would be defined as the smallest amount the utility would have to pay in order to buy out or  
26 buy down the contract. Stranded costs can also include regulatory assets unrecoverable as a  
consequence of restructuring.

1 the MGC and the price it can obtain from an alternate supplier, be it a marketer or  
2 producer. In fact, if the MGC is set too low, customers will not be able to save at all; that  
3 is, competition will exist in name only, not in fact.

4 Q WHAT DOES THE AGREEMENT SAY ABOUT THE SHOPPING CREDIT?

5 A The Agreement states that the MGC will be set at the Palo Verde electricity futures  
6 contract traded on the New York Mercantile Exchange (NYMEX), adjusted upward for  
7 losses, plus an overall adder of 3.5 mills. Moreover, the Agreement calls for the MGC to  
8 be "calculated for each rate class by adjusting for class line losses and inclusion of the  
9 appropriate load factor.<sup>3</sup> The Agreement specifies an adder of 4.0 mills for the residential  
10 and commercial classes and only 2.6 per mills for the industrial class.

11 A No.

12 Q DOES THE AGREEMENT SUPPORT THE STIPULATED ITC REVENUES AS  
13 NECESSARY TO MAINTAIN TEP'S FINANCIAL INTEGRITY?

14 A No. The Agreement offers no analysis of the minimum ITC revenues that TEP would  
15 need to maintain its financial integrity. In fact, nothing in the Agreement or TEP's pre-  
16 filed testimony provides evidence that an ITC is even necessary in the first place.<sup>4</sup> In  
17 other words, if the ultimate CTC is fully compensatory, why should the Company require  
18 an ITC if it cannot demonstrate that such collection will prevent some financial disaster?  
19  
20  
21  
22

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23 <sup>3</sup>Agreement, page 2.

24  
25 <sup>4</sup>The Agreement does provide TEP the opportunity to recover transition **revenues** to maintain its  
26 financial variability, in the event that TEP does not divest; however, those revenues would be strictly  
limited to the amounts to cover debt payments.

1 Q ARE YOU AWARE OF OTHER INSTANCES WHERE A UTILITY HAS PROPOSED  
2 THAT IT SIMPLY BE ALLOWED TO COLLECT THE DIFFERENCE BETWEEN  
3 THE FULL TARIFF RATE AND SOME INDEX-BASED GENERATION CREDIT  
4 FOR A PERIOD OF TIME AS AN INTERIM MECHANISM FOR RECOVERING  
5 STRANDED COSTS?

6 A Yes. In Montana, where competition was instituted for customers over 1,000 kW on July  
7 1, 1998, the Montana Public Service Commission (PSC) had yet to determine or quantify  
8 the net stranded costs of either PacifiCorp or Montana Power Company. Both utilities  
9 had claimed a significant amount of stranded costs related to their production assets. In  
10 addition, both companies also requested an interim CTC based on the difference between  
11 the generation component of the tariff rate and the Mid-Columbia spot index.

12 Q WHAT WAS THE END RESULT IN MONTANA?

13 A Neither utility was allowed to collect an interim CTC on that basis. Montana Power was  
14 permitted to collect an explicit CTC for regulatory assets and non-utility purchased power  
15 contracts for a specific time period. The Montana PSC accepted an Accounting Order  
16 (stipulated to by the parties) to allow for the accumulation of transition costs during the  
17 interim period. These interim transition costs will ultimately be recognized when the  
18 final stranded cost amount is determined in 1999. No allowances for true-up were  
19 provided to that explicit CTC; consequently MPC customers know precisely the amount  
20 of transition costs for which they may be held liable during the interim.

21 PacifiCorp was also allowed an Accounting Order for the accumulation of  
22 transition costs until the Commission could make a final determination of the existence  
23 and amount of PacifiCorp's transition costs.

24 Q HAS COMPETITION STARTED IN MONTANA?

25 A Yes. Competition for all Montana customers of PacifiCorp and Montana Power  
26 Company, of a size over 1,000 kW, began on July 1, 1998.

1 Q HAS THE MONTANA COMMISSION MADE A DETERMINATION OF NET  
2 STRANDED COSTS FOR THOSE TWO UTILITIES?

3 A No, not yet.

4 Q IS IT POSSIBLE FOR COMPETITION TO COMMENCE IN ARIZONA ON  
5 JANUARY 1, 1999 WITHOUT A DETERMINATION OF STRANDED COSTS BY  
6 THAT TIME?

7 A Certainly. As I stated earlier, if necessary for financial viability, the Commission could  
8 set a mechanism for recovering a fixed amount that would go toward any ultimate  
9 determination of stranded costs (including regulatory assets). Then, once a final  
10 determination of *allowable* stranded costs was made, that figure, less the interim recovery  
11 amount, would be collected with a final CTC. It would even be possible to set the final  
12 CTC equal to the interim transition charge and simply vary the recovery period so that the  
13 appropriate amount, with carrying charges, was ultimately accounted for. The utility  
14 would be made whole, while customers and suppliers alike could operate and plan  
15 intelligently in a competitive environment.

16 Q SECTION IV.B. OF THE AGREEMENT CONTAINS A "TRUE-UP" PROVISION.  
17 DOES THIS ALLAY YOUR CONCERNS ABOUT ANY POTENTIAL  
18 OVERCOLLECTION?

19 A No. This provision merely allows quarterly adjustments to the MGC if actual spot market  
20 prices differ from projected spot prices such that the Company undercollects or  
21 overcollects generation costs by more than 10% (quarterly) or 2% (annually). This  
22 provision in no way reconciles the amount of ITC revenues collected with the Final  
23 Stranded Cost Amount (FSCA) as determined after divestiture. In fact, the true-up  
24 provision for the ITC may actually harm customers if they make purchasing decisions  
25 based on generation credits that are ephemeral or illusory.<sup>5</sup>

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26 <sup>5</sup>This is a completely different situation from a mechanism that prospectively adjusts the CTC so

1 Q WILL CUSTOMERS BE AFFORDED AN OPPORTUNITY TO SAVE MONEY  
2 UNDER THE AGREEMENT?

3 A No. Given the structure of the Agreement, it is highly unlikely that customers will save  
4 any money.

5 Q WHY DO YOU BELIEVE THAT CUSTOMERS WILL BE UNABLE TO SAVE  
6 MONEY?

7 A The MGC provided to retail customers will be based on the Palo Verde Index, plus an  
8 adder of 2.6 mills to 4.0 mills, depending on their class. According to the Agreement, the  
9 adder reflects ancillary services, and reserves that (independently or indirectly through  
10 their alternative retailer) customers will need to procure in order to access the retail  
11 market. Since the Palo Verde Index is more of a spot market or opportunity sales among  
12 wholesale players, these prices are not indicative of prices that retail customers will pay  
13 for long-term firm purchases. In fact, Article IV.B even refers to the ITC in the context  
14 of a spot market. Retail consumers cannot be expected to beat a spot market in order to  
15 benefit from competition because the spot market price is indicative of wholesale  
16 opportunity transactions between large buyers and sellers. A spot market price does not  
17 reflect a long term firm price for end-users.

18 Q WILL THIS STIFLE COMPETITION?

19 A Yes, most definitely. For example, in California, the utilities are allowed to use a market  
20 backout rate as an interim mechanism until the value of the plants can be ascertained by  
21 December 31, 2001. However, PacifiCorp, one of the largest and most efficient  
22 producers of electricity in this nation, complained:

23 "California was one of the first states officially to open its retail electric  
24 marketplace to competition. From our perspective, what exists in

25 that customers do not overpay or underpay (or the utility does not overcollect or undercollect) the amount  
26 of stranded cost recovery that the Commission has found appropriate. (Much like a reconciliation factor in  
an automatic fuel adjustment clause).

1 California today is customer choice, but without competition. This is  
2 because of the way stranded costs .... are being recovered. In California,  
3 **customers are paying for these costs in a way that makes it difficult**  
4 **for them to receive significant benefits from choosing a new supplier."**  
(PacifiCorp 1997 Annual Report, page 20, emphasis added.)

5 Q YOU STATED THAT IF THE MGC IS TOO LOW, COMPETITION WILL EXIST IN  
6 NAME ONLY, NOT IN FACT. IS THERE A SIMILAR CONCERN IF THE MGC IS  
7 "TOO HIGH"?

8 A No. The working of a competitive market will serve to bring generation rates to their  
9 appropriate levels. In fact, that is the only way that a relevant market can develop.  
10 Moreover, if the utility can demonstrate that it has not had a reasonable opportunity to  
11 recover a fair share of its stranded costs, the ITC can be extended for a longer term. After  
12 all, I am not advocating that the incumbent utilities be deprived of the opportunity to  
13 recover a fair share of their stranded costs, if any.

14 Q ARE THERE ANY OTHER PROBLEMS WITH THE WAY THE AGREEMENT  
15 HANDLES THE MGC?

16 A Yes. The Agreement states: "The individual retail MGC's shall be calculated for each  
17 rate class by adjusting for class line losses and inclusion of the appropriate load factor."<sup>6</sup>  
18 How TEP plans to apply any "appropriate load factor" is presently unclear. Exhibit B to  
19 the Agreement offers a calculation of the ITC which does not provide any explanation (or  
20 existence for that matter) of the derivation of the MGC. Instead, the MGC appears to be  
21 defined as:

22 
$$[(\text{Spot market price projection} * \text{Loss Factor}) + \text{Adder}];$$
  
23 where Loss Factor is  $(1 + \text{line loss percentage})$

24 As is evident, no adjustment has been made for "load factor".

25 \_\_\_\_\_  
26 <sup>6</sup>Agreement, page 2, Section II.

1 Q SHOULD THE INDIVIDUAL RETAIL MGC'S BE ADJUSTED FOR LOAD  
2 FACTOR?

3 A As I will explain later, I believe the generation portion of the unbundled rates should be  
4 set as the residual, thereby negating the need for any load factor adjustment. This will  
5 ensure that all regulated components of the unbundled rate are based on cost, and the  
6 remaining generation component reflects the amount currently being paid by the  
7 customers.

8 Q DO YOU CONSIDER THE INDIVIDUAL RETAIL ADDERS FAIR AND LOGICAL?

9 A No, I do not.

10 Q COULD YOU ELABORATE ON THE UNFAIRNESS AND ILLOGICAL NATURE  
11 OF THE ADDER?

12 A Yes. Assuming Schedule G-1a (the Company's proposed unbundled rates) of the  
13 Agreement is correct, and using a 3.0¢ per kWh spot market price for illustration, the  
14 following table shows the disparity in collection of stranded costs:<sup>7</sup>

15

<u>Class</u>	<u>ITC per kWh</u>
Residential	1.83¢ per kWh
General Service	3.94¢ per kWh
Large Light & Power	2.82¢ per kWh
Contracts	2.83¢ per kWh
Lighting	(0.16)¢ per kWh
Public Authority	1.91¢ per kWh

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21 Several things are apparent from the above table. First, the size of the ITC is  
22 large, almost 4¢ for the General Service class, and close to 3¢ for Large Light & Power  
23 and Contracts. For many utilities, large customers do not pay much more than 4¢ per  
24

25 <sup>7</sup>Class line losses are assumed as 8% for residential, general service, lighting and public  
26 authority; and 2% for large light and power and contracts.

1 kWh for their *entire* power bill, frequently less. Here, TEP's largest customers would be  
2 required to pay over 70% of that figure, just in transition charges alone.

3 Second, Contract customers will be paying **55% more** per kWh in transition costs  
4 than Residential customers. However, this is completely at odds with the relationships  
5 indicated by the cost of service study filed by TEP last December, which shows that, on a  
6 per unit basis, the Contract class has a **23% lower** responsibility for generation fixed  
7 costs than the Residential class.

<u>Class</u>	<u>Fixed Production Costs per kWh</u>
Residential	4.12¢ per kWh
Large Light & Power	3.52¢ per kWh
Contracts	3.16¢ per kWh

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14 Q DOES THE AGREEMENT STIPULATE HOW THE PERMANENT CTC SHOULD BE  
15 ESTABLISHED?

16 A The Agreement mentions that the permanent CTC will be derived post-divestiture  
17 through either: (1) the auction proceeds, (2) an estimate of stranded costs, or (3) some  
18 combination of the two. However, if there were any more specific guidelines on  
19 establishing the permanent CTC, it was not in the material furnished to me. Moreover,  
20 the Agreement states "The revenue requirement has been allocated among classes of  
21 customers on the basis of the formula described in Section 2 of the Formula Schedule."<sup>8</sup> I  
22 could find no such formula or Formula Schedule.

23 Q HOW SHOULD THE FINAL STRANDED COST AMOUNT BE RECOVERED FROM  
24 CUSTOMERS?

25  
26 <sup>8</sup>Exhibit C to the Agreement, Page 4.

1 A That should be determined in Phase II when all the facts are known. In general, it is my  
2 opinion that stranded costs should be recovered in accordance with how production costs  
3 of this nature have historically been apportioned to these customers, giving effect to cost  
4 causation principles such as coincident loads and proper recognition of the firmness or  
5 interruptibility of some loads. In fact, I understand this type of "proportionality" is called  
6 for in the Commission's rules. Furthermore, depending on the final determination of  
7 stranded cost responsibility it may even be advisable to have different recovery periods  
8 for different customers.

9 Q DO YOU HAVE ANY OTHER COMMENTS ON STRANDED COST  
10 ARRANGEMENTS STIPULATED TO IN THE AGREEMENT?

11 A Yes. After stating that TEP shall securitize all stranded costs, Section IV. of the  
12 Agreement states as follows:

13 An allowance for an equity return on the unamortized amounts (of  
14 stranded costs) will be imputed using TEP's return on equity as  
15 authorized in Commission Decision No. 59594 applied to a  
hypothetical capital structure consisting of 35% equity and 65%  
debt.

16 I have a number of concerns with this provision. First, if TEP securitizes stranded costs,  
17 the appropriate carrying charge on unamortized amounts would be the coupon cost of the  
18 securitization bonds. Second, because TEP's capital structure reflects only 15%  
19 common equity and 85% debt, using this hypothetical structure would give TEP's  
20 shareholders a *greater* than authorized return on common equity. For example, if the  
21 authorized return on equity is 10% and the embedded cost of debt is, let us say, 6%, this  
22 arrangement is tantamount to giving TEP a return of 15.3% on its common equity. This  
23 is wholly at odds with normal regulation. Typically, Commissions will allow a *reduced*  
24 return on uneconomic assets, not an enhanced return.

25 **Unbundled Rates**

1 Q WHY ARE UNBUNDLED RATES IMPORTANT?

2 A First, unbundled rates are a basic element of retail competition. In fact, every  
3 commission order on electric industry restructuring of which I am aware, stipulates or  
4 otherwise acknowledges that unbundled rates are part and parcel of the process. The  
5 electric industry is vertically integrated. Without unbundled rates for each service,  
6 customers cannot make intelligent decisions on which services they want to retain with  
7 their current utility (assuming that the service is available on a competitive basis).  
8 Similarly, unbundled rates allow potential competitors to the utility to make decisions as  
9 to whether it is profitable to market their services in that territory.

10 Second, unbundled rates allow different jurisdictions to apply their regulatory  
11 responsibility for those cost components that remain regulated; e.g., FERC and the  
12 Arizona Commission setting cost-based rates for transmission and distribution,  
13 respectively. For competitive services, such as generation, unbundled rates allow the free  
14 market to exercise its discipline on the pricing and quality of such service.

15 Finally, unbundled rates help prevent unfair monopolistic practices in two ways.  
16 First, it avoids the practice of tying, that is, forcing customers to take one service as an  
17 unavoidable consequence of taking another. Second, it facilitates cost accounting which  
18 should prevent TEP from using the profits from its regulated activities to support its  
19 unregulated ventures. Just as important, proper cost accounting helps regulators gauge  
20 the true profitability of the regulated activities. Clear and explicit unbundled rates  
21 facilitate the task of ascertaining whether the utility is making undue profits on a  
22 regulated service. For example, if a utility is making a 20% return on equity, without  
23 unbundled rates it would be difficult to tell if it is just being extraordinarily successful in  
24 marketing power or if it is making unreasonable profits on its monopoly services.

25 Q DOES THIS MEAN THAT YOU ENDORSE UNBUNDLING FOR ALL  
26 CUSTOMERS?

1 A Yes. Unbundled rates should be available to all customers. Even customers who choose  
2 to continue to take full bundled service from TEP will best be served by a proper  
3 unbundling, since unbundling increases awareness of the changing structure of the  
4 industry and educates customers about the costs included in their electric bills. Such  
5 information plays a critical part of consumer education that will facilitate the transition to  
6 customer choice.

7 Q DO YOU AGREE WITH THE UNBUNDLED RATES THAT ARE CONTAINED IN  
8 EXHIBIT A TO THE AGREEMENT?

9 A That is difficult to say because the information filed with the Agreement is sketchy and in  
10 some respects inconsistent with the information filed by TEP in December 1997. For  
11 example, according to Schedule G-1a of Exhibit A to the Agreement, the Contracts class  
12 is responsible for 20.75% of Production costs, while the December 31, 1997 filing  
13 showed that this class was responsible for 16.41% of fuel and 13.23% of fixed production  
14 costs. My problem with analyzing the data has been compounded by TEP's failure to  
15 respond to discovery we submitted to them in October, 1998.

16 Q SHOULD RATES BE UNBUNDLED STARTING ON JANUARY 1, 1999?

17 A Absolutely. As previously explained, unbundled rates are the hallmark of a restructured  
18 electric industry. They convey valuable information to suppliers, consumers and  
19 regulators. These rates should distinguish between Production, Ancillary Services,  
20 Transmission EHV, Transmission Non-EHV, Lower Voltage Distribution, and Customer  
21 services such as Metering and Billing.

22 Q HOW SHOULD THE RATES BE UNBUNDLED?

23 A Distribution is still a monopoly, to be regulated by the Arizona Corporation Commission.  
24 Consequently, distribution rates must be based on cost of service. In fact, with customer  
25 choice, it is all the more important that the distribution rates be based on cost causation so  
26 as not to distort the price signals between the generator and the meter. The embedded

1 cost study should be used to set distribution and metering/billing rates.

2 Next, the transmission (EHV and non-EHV) and ancillary services component of  
3 the unbundled rate should be based upon the FERC Open Access Tariff. It should also be  
4 allocated among the service classes in accordance with the allocation methods accepted  
5 by FERC. It is also my recommendation that specific transition charges be established  
6 based on cost-causative principles as well. For production, the Commission can either  
7 use the embedded study or alternatively, set the unbundled generation component as the  
8 residual after all the other rates have been set. This latter approach is the recommended  
9 course if the objective is to maintain revenue neutrality, that is, have the sum of all  
10 unbundled components equal to the present bundled tariffs.

11 Q IF THE COMMISSION DECIDES THAT THE SUM OF THE UNBUNDLED  
12 COMPONENTS SHOULD EQUAL THE CURRENT INDIVIDUAL RATES, WHY  
13 SHOULD THE GENERATION COMPONENT BE THE RESIDUAL?

14 A It is the transmission and distribution components that will remain monopoly services and  
15 hence will require regulatory oversight. Therefore, it is these rates that must be set at cost  
16 by this Commission or by FERC. This will allow market forces to work and set the  
17 generation prices at appropriate levels. Clearly, regulators should not decide prices that  
18 can be set by unfettered competitive forces. What is required, however, are cost based  
19 rates and transition charges that are low enough to allow the market to work.

20 Q HAVE YOU BEEN ABLE TO COMPUTE ANY SPECIFIC TRANSMISSION RATES  
21 FOR THE LARGE LIGHTING & POWER AND SPECIAL CONTRACTS CLASS?

22 A Yes. Based on TEP's FERC approved Open Access Transmission Tariff, I have  
23 determined that the following rates should apply:

24	Ancillary Services	\$0.75 per kW per month
25	EHV Transmission Service	\$2.00 per kW per month
26	Non-EHV Transmission Service	\$0.83 per kW per month

1 **Modification of the Agreement**

2  
3 Q SHORT OF COMPLETE REJECTION, HOW SHOULD THE AGREEMENT BE  
4 MODIFIED SO AS TO ADDRESS THE PROBLEMS THAT YOU HAVE  
5 DISCUSSED IN THIS TESTIMONY?

6 A It is my opinion that the following revisions are imperative if competition is to have a  
7 chance. First, unbundled transmission and distribution rates as set forth in Exhibit A to  
8 the Agreement should be accepted on a provisional basis only. As soon as possible after  
9 the divestiture is completed, or by July 1, 2000 at the latest, a Phase II to this docket  
10 should commence. In Phase II, intervenors could present evidence as to modifications  
11 that should be made to those unbundled rates. Phase II would also be used to determine  
12 the FSCA based on the results of the auction, as well as the appropriate recovery period  
13 for that FSCA.

14 Second, I recommend that if an interim ITC be instituted, and it is not clear that  
15 one should be, it be set at a level *no greater than is absolutely necessary* to prevent TEP  
16 from defaulting on its financial obligations. I believe a rebuttable assumption would be  
17 an ITC revenue of 1¢ per kWh times the total annual retail sales. This should produce  
18 approximately \$75 million on an annual basis. This amount should be apportioned to  
19 classes in proportion to the 4 CP allocator as contained in the December cost of service  
20 study.

21 Third, the MGC (the resulting "shopping credit") should be implicit as the  
22 difference between the unbundled generation component of the tariff rate and the explicit  
23 ITC as calculated in the previous step.

24 Fourth, the Commission should declare that in Phase II it will compare the ITC revenue  
25 collected from each class during the interim period with the responsibility of that class for  
26 the Final Stranded Cost Amount and set the permanent CTC accordingly. The interim

1 period would be defined as the period January 1, 1999 until the effective date of the  
2 tariffs emanating from Phase II.

3 Q DOES THIS CONCLUDE YOUR TESTIMONY?

4 A Yes, it does.

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**APPENDIX A**

**Qualifications of Alan Rosenberg**

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Alan Rosenberg. My business mailing address is P. O. Box 412000, St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and am a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was awarded a Bachelor of Science Degree from the City College of New York in 1964 and a Doctorate of Philosophy in Mathematics from Brown University in 1969. Subsequently, I held an Assistant Professorship of Mathematics at Wesleyan University in Connecticut. In the summer of 1975, I was a Visiting Fellow at Yale University. From July, 1975 through January, 1981, I was Assistant Controller for a division of National Steel Products Company. My responsibilities there included supervision of management accounting, cost accounting and data processing functions. I was also responsible for internal control, working capital levels, budget preparation, cash flow forecasts and capital expenditure analysis. From February, 1981, through December, 1981, I was Project Manager of the Steel Fabricating and Products Group, National Steel Corporation, responsible for implementing an integrated general ledger system. I have published in major academic journals and am a member of the International Association for Energy Economics.

In January, 1982, I joined the firm of Drazen-Brubaker & Associates, Inc., the predecessor of Brubaker & Associates. Since that time, I have presented expert testimony on the subjects of industry restructuring, open access transmission, marginal

1 and embedded class cost of service studies, prudence and used and useful issues, electric  
2 and gas rate design, revenue requirements, natural gas transportation issues, demand-side  
3 management, and forecasting.

4 I have previously testified before the Federal Energy Regulatory Commission as  
5 well as the public service commissions of Arizona, Connecticut, Delaware, Florida,  
6 Illinois, Iowa, Massachusetts, Michigan, Montana, New Jersey, New Mexico, New York,  
7 Ohio, Rhode Island, Vermont, Virginia and the Provinces of Alberta, British Columbia,  
8 Nova Scotia, and Saskatchewan in Canada. I was an invited speaker at the NARUC  
9 Introductory Regulatory Training Program and a panelist at a conference on LDC and  
10 Pipeline Ratemaking sponsored by the Institute of Gas Technology. I have presented a  
11 paper on stranded costs at the 21st Annual International Conference of the International  
12 Association for Energy Economics. I have also spoken at several conferences on the  
13 topic of competitive sourcing of electricity for industrial users.

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BEFORE THE ARIZONA CORPORATION COMMISSION

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Commissioner

IN THE MATTER OF THE APPLICATION  
OF TUCSON ELECTRIC POWER  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01933A-98-0471

IN THE MATTER OF THE FILING OF  
TUCSON ELECTRIC POWER COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01933A-97-0772

IN THE MATTER OF THE APPLICATION  
OF ARIZONA PUBLIC SERVICE  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01345A-98-0473

IN THE MATTER OF THE FILING OF  
ARIZONA PUBLIC SERVICE COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN  
THE PROVISION OF ELECTRIC SERVICES  
THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

DIRECT TESTIMONY OF DR. ALAN ROSENBERG

On Behalf of Cyprus Climax Metals Company,  
ASARCO Incorporated and Arizonans for  
Electric Choice and Competition

1 Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A My name is Alan Rosenberg and my business address is 1215 Fern Ridge Parkway, Suite  
3 208, St. Louis, Missouri 63141-2000.

4 Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

5 A I am a consultant in the field of public utility regulation and a principal in the firm of  
6 Brubaker & Associates, Inc., energy, economic and regulatory consultants.

7 Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

8 A This is summarized in Appendix A to this testimony.

9 Q ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS  
10 PROCEEDING?

11 A I am testifying on behalf of Arizonans for Electric Choice and Competition (AECC)<sup>1</sup>,  
12 ASARCO Incorporated and Cyprus Climax Metals Company.

13 Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

14 A I have been asked to review the proposed Settlement Agreement (Agreement) between  
15 the Staff and Arizona Public Service Company (APS). In particular, it was requested that  
16 I focus my attention on the proposed method for granting APS recovery of any stranded  
17 costs that it may have and for allowing customers the opportunity to save money by  
18 choosing an alternative supplier. Consequently, my silence on any other aspects of the  
19 Agreement should not be interpreted as assent or approval.

20 Q WHAT REASONS DOES THE STAFF AND APS OFFER FOR THE ADOPTION OF  
21 THE APS AGREEMENT?

22

23 <sup>1</sup> Arizonans for Electric Choice and Competition is a coalition of companies and associations who  
24 support the introduction of competition in the generation of electric power in Arizona. AECC's members  
25 include Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell,  
26 Allied Signal, Cyprus Climax Metals, ASARCO, Phelps Dodge, Homebuilder's Association of Central  
Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association  
of Industries, Arizona Multi-Housing Association, Arizona Rock Products Association, Arizona Restaurant  
Association, Arizona Association of General Contractors, the Arizona Retailers Association and Enron.

1 A The alleged advantages of the agreement, as portrayed by witnesses for Staff and APS  
2 are:

- 3 1. It provides for unbundled rates on January 1, 1999;
- 4 2. It provides for rate reductions of 1% per year over the next 4 years;<sup>2</sup>
- 5 3. It will remove market power as a result of the swap of transmission assets for  
6 certain generation assets between APS and TEP and the establishment of an ISO;
- 7 4. It removes the need for lengthy administrative proceeding;
- 8 5. It calls for APS to transfer its generating assets to a marketing affiliate; and
- 9 6. It calls for APS to dismiss litigation seeking to block the Commission's Electric  
10 Competition Rules.

11 Q ARE THESE REASONS SUFFICIENT TO APPROVE THE AGREEMENT AS IS?

12 A No. As, I explain in this testimony, the Agreement will not result in any meaningful  
13 competition before 2004. Moreover, any perceived benefits are either insufficient to  
14 compensate for the absence of competition or will be achievable without the agreement.  
15 For example, it may not be possible for the Commission to mandate a 1% rate reduction  
16 by January 1999. On the other hand, authentic competition ought to confer reductions far  
17 in excess of 1% or even 4%. While the exact savings will depend upon the situation,  
18 most observers of restructuring expect savings of between 10% and 20% from vigorous  
19 competition.

20 Q DOES THE AGREEMENT REMOVE THE NEED FOR AN ADMINISTRATIVE  
21 PROCEEDING?

22 A It does if the Commission is content to give APS between \$300 million and \$790 million  
23 in above market revenues<sup>3</sup> (depending upon whose estimate of market prices is more  
24

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25 <sup>2</sup> The reductions beyond the first two years only apply to APS residential customers.

26 <sup>3</sup> See page 8 of the testimony of Ms. Lee Smith for the source of these figures.

1 correct) without ever hearing evidence on whether APS has net, non-mitigatable stranded  
2 costs. Moreover, this sum is in addition to untold hundreds of millions more for its  
3 regulatory assets.

4 It does if the Commission is content to allow rates for distribution to go into effect  
5 without a contested hearing on whether those rates reflect the actual cost of APS of  
6 providing those services. The point I am trying to make is that it may eliminate (or defer)  
7 the bother of an administrative proceeding, but at a great cost by the relinquishing of  
8 regulatory oversight on significant issues.

9 Q DO YOU AGREE THAT THE INSTITUTION OF UNBUNDLED RATES ON  
10 JANUARY 1, 1999 IS A BENEFIT OF THE AGREEMENT?

11 A Yes, I do. On that score, I agree with Mr. Davis who stated that unbundled rates are  
12 essential to the operation of retail competition. However, I would add the modifier  
13 "appropriate" before the word unbundled. Unfortunately, to the best of my knowledge,  
14 neither the Staff nor the Company has filed any studies or analyses to support the  
15 development of those rates. Consequently, it is my recommendation that the unbundled  
16 rates sponsored by Mr. Davis of APS be allowed to take effect, but only on an interim  
17 basis until an expeditious hearing can be conducted to allow other parties to challenge  
18 those rates.

19 Q DO YOU HAVE ANY REASON TO DOUBT THE APPROPRIATENESS OF THE  
20 PROPOSED UNBUNDLED RATES?

21 A Yes. I have examined the Extra Large General Service rate. I calculated that, for an 80%  
22 load factor customer in this largest of classes, the customer would be paying 1.6 cents  
23 per kWh for "services" besides Generation, Transmission and Metering & Billing. This  
24 is a very large number. By way of comparison, there are numerous utilities, some even in  
25 relatively high priced regions such as the Middle Atlantic states where such a large, high  
26

1 load factor customer, served at transmission voltage would have a total bill of around 4  
2 cents per kWh, often less than that. Consequently, I find it difficult to accept that these  
3 extraneous charges could be 40% or more of a similarly situated customer's total bill.

4 Q CAN YOU OFFER ANY SUGGESTIONS AS TO HOW THOSE RATES COULD BE  
5 IMPROVED RIGHT NOW?

6 A Yes. The largest part of that 1.6 cents, approximately 1 cent per kWh, is attributable to  
7 regulatory assets. If APS's regulatory assets are indeed of that magnitude, I strongly  
8 suggest stretching out the recovery of those assets to approximately twice the recovery  
9 period. This would allow more "headroom" for customers to save money and would  
10 strengthen competition. At the same time, because APS would be allowed to accrue a  
11 return on the unrecovered assets, the Company would not suffer in its earnings.

12 Q MR. WILLIAMSON OF THE STAFF ASSERTS THAT THE TRANSFER OF  
13 TRANSMISSION ASSETS TO THE TRANSCO THAT IS BEING FORMED AS AN  
14 AFFILIATE OF TEP WILL NOT CREATE A NEW MONOPOLY WITH  
15 HORIZONTAL MARKET POWER. PLEASE COMMENT.

16 A I agree with Mr. Williamson that an independent system administrator and the  
17 establishment of an ISO (which the FERC must approve) should prevent the owners of  
18 the transmission system from exerting market power. However, we do not need this  
19 Agreement for that purpose. Under Order 888, transmission access is supposed to be  
20 non-discriminatory and comparable. If the FERC is doing its job, these provisions of the  
21 Agreement are superfluous.

22 What is notably lacking in Mr. Williamson's testimony however, is any  
23 discussion of the potential for horizontal market power on the generation side by APS.  
24 By sanctioning the swap, and by not giving APS any motivation to divest generation, the  
25 Agreement actually exacerbates market concentration on the generation side.

26

1 Q. YOU HAVE NOT ADDRESSED THE ALLEGED ADVANTAGE OF APS  
2 DROPPING ITS LITIGATION TO THWART THE COMMISSION'S ELECTRIC  
3 COMPETITION RULES. PLEASE COMMENT.

4 A Well, it is true that there would be no need for APS to proceed with the litigation as this  
5 Agreement serves essentially the same purpose. However, if the threat of litigation is the  
6 hammer necessary to induce adoption of this Agreement, I would counsel against  
7 succumbing to such pressure. Competition has the support of both the Commission and  
8 the Arizona Legislature. Litigation could do no more than delay the inevitable and I dare  
9 say consumers would rather see meaningful competition instituted somewhat later than  
10 sham competition instituted on January 1, 1999.

11 **Stranded Costs and the Ability to Compete**

12 Q WHAT IS THE SUBJECT OF THIS SECTION OF YOUR TESTIMONY?

13 A In this section, I discuss the recovery of stranded costs and its mirror image, the ability of  
14 customers to save money by virtue of competition.

15 Q WHAT ARE STRANDED COSTS?

16 A Stranded costs are properly defined as the difference between the book value of a utility's  
17 generation assets and the price those assets could command in a competitive  
18 environment.<sup>4</sup> As Ms. Smith (witness for the Staff) notes:

19 "Generation costs may also be stranded, if the investment in generation  
20 assets that the Company still needs to recover is greater than the market  
21 value of those assets." (Direct Testimony of Lee Smith, Page 6, emphasis  
22 added.)

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23 <sup>4</sup> There may also be stranded costs associated with purchase power contracts, in which case the  
24 stranded cost would be defined as the smallest amount the utility would have to pay in order to buy out or  
25 buy down the contract. The terms stranded costs can also apply to regulatory assets unrecoverable as a  
26 consequence of restructuring. The stranded generation-related regulatory assets of APS would be  
recovered through a separate distinct charge. This testimony does not directly address the  
appropriateness of this charge.

1 Q WHAT METHOD DOES THE AGREEMENT PROPOSE FOR GRANTING APS  
2 RECOVERY OF STRANDED COSTS?

3 A For recovery of stranded costs, the Agreement uses the term "Customer Transition  
4 Charge" or CTC. In most jurisdictions, this same acronym is used, but refers instead to a  
5 "Competitive Transition Charge." Under either label, however, a CTC is a charge or rate  
6 that is used to allow a utility to recover all or part of its so-called "stranded costs."

7 Q WHAT METHOD DOES THE AGREEMENT PROPOSE FOR ALLOWING  
8 CUSTOMERS THE OPPORTUNITY TO SAVE MONEY WHEN CHOOSING AN  
9 ALTERNATIVE SUPPLIER?

10 A The Agreement provides a "Shopping Credit" for customers that choose an alternate  
11 supplier. In the Agreement, the term "Market Generation Credit" (MGC) is used to  
12 represent this Shopping Credit. Regardless of its label though, the customer's opportunity  
13 for savings hinges critically on the credit amount.

14 Q IS THERE A RELATIONSHIP BETWEEN THE AMOUNT THAT APS WILL  
15 RECOVER FOR ANY STRANDED COSTS THAT IT MAY HAVE AND THE  
16 OPPORTUNITY THAT CUSTOMERS MAY HAVE TO SAVE MONEY?

17 A Yes. Given the structure of the Agreement, such a relationship does exist. According to  
18 Exhibit A of the Agreement, the recovery of stranded costs will be through the CTC:

19 
$$\text{CTC Recovery} = \text{Tariff Generation Revenue} - \text{Shopping Credit Revenue}^5$$

20 However, from the perspective of the customers, the Agreement implicitly provides that:

21  
22 
$$\text{Customer Savings} = \text{Shopping Credit Revenue} - \text{Customer Acquisition Price}$$

23  
24 <sup>5</sup> The actual formula cited in the Exhibit states that:  
25  $\text{CTCS} = [(\text{Tariff Generation Charges}) * (\text{Billing Determinants})] - [(\text{MGC} + \text{Adder}) * (\text{Billing Determinants})]$ .  
26 However, the adder in that equation was probably put in erroneously since the MGC (or Market Generation Credit) already has an adder in it.

1 Rearranging the above two equations we have:

$$\begin{array}{l} \text{Customer Savings} = \text{Tariff Generation Revenue} - \text{Customers Acquisition} \\ \text{Price} - \text{CTC Revenues} \end{array}$$

5 As the above equation makes clear, the higher the CTC, the less customers will save.  
6 Likewise, the lower the Shopping Credit (i.e., the MGC), the less customers will save. In  
7 fact, if the Shopping Credit is too low customers will not be able to save at all, that is,  
8 competition will exist in name only, not in fact.

9 Q WHAT DOES THE AGREEMENT SAY ABOUT THE "SHOPPING CREDIT"?

10 A The Agreement states that initially the MGC will be set at the Palo Verde electricity  
11 futures contract traded on the New York Mercantile Exchange (NYMEX), adjusted  
12 upward for losses, plus an adder set at 3.0 mills. Moreover, the Agreement calls for the  
13 adder to be "adjusted" by the ratio of the system load factor to the customer's coincident  
14 load factor.

15 Q HAS APS QUANTIFIED ITS NET STRANDED COST EXPOSURE?

16 A No, APS has provided no estimate of its stranded costs, nor does the Agreement quantify  
17 the amount of stranded costs for APS. In fact, it is not evident that APS has any stranded  
18 costs. In its 1997 Annual Report, APS noted that its generation resources "are  
19 competitive, ranking about the middle of large utilities on the basis of production cost per  
20 kilowatt-hour."

21 Q HAS APS QUANTIFIED HOW MUCH IT WOULD RECOVER FOR NET  
22 STRANDED COSTS UNDER THE AGREEMENT?

23 A Ms. Smith estimates that APS will collect \$300 million in CTC revenue over the next six  
24 years. However, she also notes that if APS's estimate of market prices are correct, APS  
25  
26

1 would collect \$790 million over that time. Moreover, these figures do not include a  
2 recovery of perhaps \$200 million per year in regulatory assets.

3 Q IF THE AGREEMENT DOES NOT ALLOW FOR A DETERMINATION OF THE  
4 LEVEL OF APS'S NET STRANDED COSTS, HOW CAN THE COMMISSION  
5 DETERMINE WHETHER APS HAS IN FACT COLLECTED AN APPROPRIATE  
6 LEVEL OF ITS STRANDED COSTS?

7 A The answer is: it cannot. Obviously, such a determination would be impossible. One  
8 cannot reconcile to a figure that is undetermined. On those grounds alone the Agreement,  
9 as it stands, should be rejected.

10 Q DOES THE AGREEMENT SUPPORT THE STIPULATED CTC REVENUES AS  
11 NECESSARY TO MAINTAIN APS'S FINANCIAL INTEGRITY?

12 A No. There is no analysis of the minimum CTC revenues that APS would need to  
13 maintain its financial integrity.

14 Q DO YOU KNOW OF ANY STATE WHERE UTILITIES ARE ALLOWED TO  
15 COLLECT AND KEEP STRANDED COSTS THROUGH A CTC WITHOUT  
16 VERIFYING AND SUBSTANTIATING THAT IT INDEED HAS NET,  
17 DEMONSTRABLE, UNMITIGABLE STRANDED COSTS?

18 A No, not to my knowledge. For example, Montana law on the subject requires that any  
19 recoverable stranded costs must be "**net verifiable generation-related and electricity**  
20 **supply costs**" that become unrecoverable as a result of open access.<sup>6</sup> I am aware of  
21 instances where the utility may collect stranded costs on an interim basis until there is a  
22 day of reckoning. (In fact, if customers are not allowed retail access, in a sense the utility  
23 continues to collect stranded costs through the general tariff.)

24

25 <sup>6</sup> SB 390, Section 69-8-103 (22), MCA, emphasis added. The Montana law refers to stranded costs as  
26 transition costs. Also, recovery of transition costs related to tangible generation assets (as opposed to regulatory  
assets or purchase power contracts) is limited to four years.

1 Q IN YOUR OPINION, WILL THE AGREEMENT RESULT IN APS RECOVERING  
2 LESS THAN OR MORE THAN ANY STRANDED COSTS IT MAY HAVE?

3 A It is my firm opinion that APS will recover significantly more than its legitimate stranded  
4 costs. This is particularly ironic since according to Decision 60977, APS is not even  
5 entitled to 100% of stranded costs since it is not divesting itself of any generation. Thus,  
6 should this ill-conceived Agreement be approved without substantial modification, the  
7 Commission's conclusions and findings of less than six months ago, will have been  
8 circumvented.

9 Q WHY ARE YOU CONVINCED THAT APS WILL RECOVER SIGNIFICANTLY  
10 MORE THAN ITS LEGITIMATE STRANDED COSTS?

11 A First, it has been my experience that a limited "difference in revenue" type approach  
12 (such as the one contemplated in the Agreement) for gauging stranded costs significantly  
13 underestimates the actual market value of these production assets. Almost every sale of  
14 generation plant has produced sales values far in excess of what most observers had  
15 expected prior to the sale. As but one example, Montana Power Company (MPC)  
16 through a lost revenue method, claimed over \$160 million in stranded cost. However,  
17 they recently sold their plants for 55% *above* book value. An auction of plants will  
18 always yield a lower stranded cost figure than any other method because an auction  
19 produces winning bids from purchasers with the most optimistic outlook - those who  
20 believe they can run the plants most efficiently and sell the output for the most revenue.

21 Second, the problem is compounded by only doing a "difference in revenue"  
22 approach for six years. Most observers believe that market prices today are abnormally  
23 low and will rise over time while the regulated revenue requirement (or price) will fall  
24 over time as the capital cost depreciates. By giving APS the negative difference in the  
25 beginning years, but not crediting customers with the relatively lower cost of APS's  
26

1 efficient units in the later years, APS collects more than it would if the process were to  
2 continue through the life of the unit.<sup>7</sup>

3 Third, by neglecting to perform this analysis for each plant individually, the  
4 process overstates the stranded cost associated with inefficient plants as well. This is  
5 because the stranded cost of any plant, regardless of its efficiency, is necessarily limited  
6 by the book value of that plant less the salvage value of the land. However, in a  
7 difference in revenue approach, this real-world limitation is totally ignored.

8 Fourth, the above problems are further exacerbated by the Agreement's stipulation  
9 that the CTC may never be allowed to go negative.<sup>8</sup>

10 Q ARE YOU AWARE OF ANY OTHER UTILITY THAT HAS PROPOSED THAT IT  
11 SIMPLY BE ALLOWED TO COLLECT THE DIFFERENCE BETWEEN THE FULL  
12 TARIFF RATE AND SOME INDEX BASED GENERATION CREDIT FOR A  
13 PERIOD OF TIME?

14 A Yes. PacifiCorp made a similar proposal to the one called for in the agreement as part  
15 of its transition plan that it filed with the Montana PSC. The main differences were that  
16 PacifiCorp's proposal used the Mid-Columbia index, PacifiCorp's market generation  
17 credit only lasted four years, and there was no adder.

18 Q WHAT WAS THE REACTION OF THE MONTANA PSC TO THE PACIFICORP  
19 PROPOSAL?

20  
21 <sup>7</sup> Of course, the worst possible case from the perspective of the customers is to allow these differences to be  
22 collected only up to the "crossover" point where the revenue requirement of the assets dip below the revenues that  
23 an owner could achieve in a competitive environment. While I do not know exactly where this "crossover" point  
24 would be (in fact, it is doubtful if anyone can accurately predict where this crossover point would be, which is why I  
am uncomfortable with any "lost revenue approach" that does not extend for the life of the asset), I suspect that six  
years would be pretty close.

25 <sup>8</sup> There seems to be some confusion on the part of the Staff regarding this point. In her direct testimony,  
26 Ms. Smith implies that the CTC could go negative or the amount could be credited to customers in future months.  
Yet, the Agreement specifically states that the CTC cannot be negative.

1 A In its Order 59876 dated September 22, 1997, the Montana PSC found PacifiCorp's  
2 Transition Plan deficient. The Commission stated:

3 The Commission finds PacifiCorp's Plan incomplete and inadequate . . .  
4 (t)he Plan fails to provide an affirmative showing of the Company's  
5 transition costs, which reflects all reasonable mitigation and the value of  
6 all generation assets, liabilities and supply costs based on one of the Act's  
7 listed valuation methods . . . (Finding 11)

7 Q HAS COMPETITION STARTED IN MONTANA?

8 A Yes. Competition for all Montana customers of Pacificorp and Montana Power  
9 Company, of a size over 1,000 kW, began on July 1, 1998.

10 Q HAS THE MONTANA COMMISSION MADE A DETERMINATION OF NET  
11 STRANDED COSTS FOR THOSE TWO UTILITIES?

12 A No, not yet.

13 Q IS IT POSSIBLE FOR COMPETITION TO COMMENCE IN ARIZONA ON  
14 JANUARY 1, 1999 WITHOUT A DETERMINATION OF STRANDED COSTS BY  
15 THAT TIME?

16 A Certainly. If necessary for financial viability, this Commission could set a mechanism for  
17 recovering a fixed amount that would go toward any ultimate determination of stranded  
18 costs (including regulatory assets). Then, once a final determination of *allowable*  
19 stranded costs was made, that figure, less the interim recovery amount, would be  
20 collected with a final CTC. It would even be possible to set the final CTC equal to the  
21 interim transition charge and simply vary the recovery period so that the appropriate  
22 amount, with carrying charges, was ultimate accounted for. The utility would be made  
23 whole, while customers and suppliers alike could operate and plan intelligently in a  
24 competitive environment.

25 Q MR. DAVIS STATES THAT EXHIBIT A OF THE AGREEMENT CONTAINS A  
26 RECONCILIATION PROCEDURE THAT PREVENTS OVER/UNDER

1 COLLECTION OF STRANDED COSTS. DOES THIS ALLAY YOUR CONCERNS?

2 A No. That assertion is terribly misleading. One cannot reconcile to a figure that is never  
3 determined. This provision merely trues up the futures contract prices with the actual  
4 Palo Verde prices as determined by the average of the last three trading days for that  
5 month. This provision in no way reconciles the amount of CTC revenues collected with  
6 any verifiable demonstration of stranded costs.

7 Q WILL CUSTOMERS BE AFFORDED AN OPPORTUNITY TO SAVE MONEY  
8 UNDER THE AGREEMENT?

9 A No. Given the structure of the Agreement, it is highly unlikely that customers will save  
10 any money.

11 Q WHY DO YOU BELIEVE THAT CUSTOMERS WILL BE UNABLE TO SAVE  
12 MONEY?

13 A The Shopping Credit (MGC) provided to retail customers will be based on the Palo Verde  
14 index, plus an Adder of 3 mills. Since the Palo Verde Index is more of a spot market or  
15 opportunity sales among wholesale players, these prices are not indicative of prices that  
16 retail customers will pay for long-term firm purchases. The Adder is not much help  
17 because it appears necessary simply to credit customers for ancillary services that  
18 (independently or indirectly through their alternative retailer) they will need to procure in  
19 order to access the retail market.<sup>9</sup>

20 In fact, the Agreement betrays the skepticism of the Staff that competition will be  
21 allowed to flourish since it calls for raising the adder in 2001 to 3.5 mills if at least a  
22 quarter of the eligible load has not elected an alternative supplier. The unanswered  
23 questions are:

24

25 <sup>9</sup> The Agreement between Staff and TEP stipulates a larger adder to reflect "ancillary services,  
26 capacity, reserves and other generation costs."

1. Why only increase the adder by 0.5 mills? What happens if that is still not sufficient to allow for meaningful competition?
2. Why wait until 2001 to see if the Agreement is defective?
3. Does APS's marketing affiliate count as an "alternate supplier"?

Q WILL THIS STIFLE COMPETITION?

A Yes, most definitely. For example, in California, the utilities are allowed to use a market backout rate as an interim mechanism until the value of the plants can be ascertained by December 31, 2001. However, PacifiCorp, one of the largest and most efficient producers of electricity in this nation, complained:

"California was one of the first states officially to open its retail electric marketplace to competition. From our perspective, what exists in California today is customer choice, but without competition. This is because of the way stranded costs .... are being recovered. In California, **customers are paying for these costs in a way that makes it difficult for them to receive significant benefits from choosing a new supplier.**" (PacifiCorp 1997 Annual Report, page 20, emphasis added.)

Q MS. SMITH STATES THAT THE STAFF'S "OBJECTIVE WAS TO ESTABLISH THE SHOPPING CREDIT AT OUR BEST ESTIMATE OF THE COST OF ACQUIRING POWER ON THE COMPETITIVE MARKET." PLEASE RESPOND.

A In the first place, Ms. Smith has offered absolutely no empirical evidence to support her claim. Secondly, Ms. Smith does not attempt to distinguish between retail markets and wholesale markets, between short term prices and long term prices, between firm power and interruptible power, between flat predictable blocks of energy and unpredictable loads that vary hour to hour. Finally, I would remind this Commission that predictions of market prices of electricity by Commission Staffs and others have led to some very uneconomic purchased power contracts over the years.

1 Q YOU STATED THAT IF THE MGC IS TOO LOW, COMPETITION WILL BE STILL-  
2 BORN. IS THERE A SIMILAR CONCERN IF THE MGC IS "TOO HIGH"?

3 A No. The working of a competitive market will serve to bring generation rates to their  
4 appropriate levels. In fact, that is the only way that a relevant market can develop.  
5 Moreover, if the utility can demonstrate that it has not had a reasonable opportunity to  
6 recover a fair share of its stranded costs, the CTC can be extended for a longer term.

7 Q MS. SMITH STATES THAT A SHOPPING CREDIT SET "TOO HIGH" MAY NOT  
8 INCREASE ECONOMIC EFFICIENCY BECAUSE IT WILL ALLOW SUPPLIERS  
9 TO MAKE "ADDITIONAL PROFITS" BY NOT PROVIDING THEIR "BEST"  
10 PRICES. PLEASE RESPOND.

11 A This is a curious concern, considering that Mr. Williamson and Mr. Davis both maintain  
12 that the Agreement will provide "meaningful" competition. The fears raised by Ms.  
13 Smith, of windfall profits by alternative suppliers, are simply unfounded. *Competition* is  
14 the vehicle by which windfall profits are avoided. The only danger of windfall profits is  
15 by APS if the Agreement is adopted, for then competition will not exist. On the other  
16 hand, if there is meaningful competition, then there will be many competitors, not the few  
17 envisioned by Ms. Smith. And if the Agreement will result in many competitors, my  
18 proposal would certainly result in even fiercer competition.

19 Q ARE THERE ANY OTHER PROBLEMS WITH THE WAY THE AGREEMENT  
20 HANDLES THE MGC?

21 A Yes. Besides the fact that the Adder is too small, the Arrangement calls for the Adder to  
22 be multiplied by a factor equal to the system load factor divided by the class' load factor.  
23 This is inappropriate for a number of reasons:

- 24  
25 1. Such an adjustment divorces the relationship between stranded cost recovery and  
26 stranded cost responsibility. Stranded costs are, by definition, APS's fixed  
uneconomic generation commitments. As such, it is only fair and logical that

1 these costs be apportioned and recovered in accord with traditionally approved  
2 and sanctioned cost allocation methods.<sup>10</sup> The proposed adjustment factor for the  
3 Adder flies in the face of such standards.

4 2. Even if one views the Adder only from the perspective of a Market price  
5 adjustment (and ignores the implications on stranded cost recovery), the multiplier  
6 would only be appropriate if it were completely demand related, as opposed to  
7 energy related.

8 3. Even if one were to completely discount the above problems, the adjustment  
9 would have to be done on a customer-specific basis and should also change month  
10 to month as load factors change. In my view, this is overly complex and  
11 impractical.

12 4. The adjustment is unfair to higher load factor customers and would make it even  
13 more improbable that these customers could attract reasonable offers.

14 Q SHORT OF COMPLETE REJECTION, HOW SHOULD THE AGREEMENT BE  
15 MODIFIED TO ADDRESS THE PROBLEMS THAT YOU NOTE IN THIS  
16 TESTIMONY?

17 A At least revisions are imperative to address these problems. **First**, if APS is to be  
18 excused from a thorough evidentiary hearing to determine its stranded costs, and also  
19 refuses to subject its generation assets to a market test, the shopping credits must be  
20 significantly expanded. **Second**, if an MGC approach is adopted, the CTC must be  
21 allowed to go negative. **Third**, if the Commission is not going to determine and fix the  
22 amount of stranded costs APS will recover through the CTC, I recommend that the ACC  
23 significantly shorten the transition period from six years to no more than three years.<sup>11</sup>  
24 **Fourth**, no more than nine months should elapse before the Commission examines and  
25 decides on the interim unbundled rates.

26 <sup>10</sup> For example, an interruptible customer should have far less responsibility for a utility's stranded capacity costs than a firm customer of the same size.

<sup>11</sup> The exception would be for the recovery of regulatory assets and any cost recovery that the Commission deems necessary for the sale and provision of reliable service.

1 If these suggestions, or possibly similar ones put forth by other parties, are not  
2 adopted, customers on the APS system will not see the benefits of competition until 2004  
3 at the earliest. Even then, competition may be difficult if APS is left with windfall profits  
4 that can keep out other potential rivals for retail sales.

5 Q HOW WOULD YOU PROPOSE TO ENLARGE THE SHOPPING CREDIT?

6 A There are several options that could be done either independently or in conjunction with  
7 one another. If the CTC is to be derived as a residual, as the Agreement envisions, the  
8 most important thing to do is to mandate a larger Adder. In my opinion, an adder of a flat  
9 6 mills is an absolute minimum if there is to be viable competition in APS's service  
10 territory. Assuming that 25% of total load opts for an alternative supplier, this would  
11 only impact APS's after tax recovery by approximately \$9 million in the first year, hardly  
12 an amount that would jeopardize APS's financial integrity. Alternatively, if the CTC is  
13 not going to be derived as a residual, I would recommend simply giving APS recovery of  
14 regulatory assets and leave the shopping credit as the unbundled generation component of  
15 the tariff.

16 Q DO YOU FEEL YOUR PROPOSAL IS IN ACCORD WITH BOTH THE LETTER  
17 AND SPIRIT OF THIS COMMISSION'S PREVIOUS FINDINGS?

18 A Yes. In Decision 60977 the ACC found:

19 For Affected Utilities that do not choose to divest their generation assets,  
20 the best incentive to mitigate is for the Commission to create a risk that  
21 not all stranded costs will necessarily be recoverable.

22 I believe my proposal is fully in accord with the intent of that proposal. It fairly strikes a  
23 balance between the right of the customer to have a prospect for meaningful savings, the  
24 ability of an alternative supplier to have a potential for a profit, and the Commission's  
25 desire to give the Affected Utility an opportunity to recover stranded costs and meet their  
26

1 existing financial obligations. If APS feels that my formula does not provide that  
2 opportunity, the burden of proof should be on APS to demonstrate otherwise.

3 Q DOES THIS CONCLUDE YOUR TESTIMONY?

4 A Yes, it does.

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1 and embedded class cost of service studies, prudence and used and useful issues, electric  
2 and gas rate design, revenue requirements, natural gas transportation issues, demand-side  
3 management, and forecasting.

4 I have previously testified before the Federal Energy Regulatory Commission as  
5 well as the public service commissions of Arizona, Connecticut, Delaware, Florida,  
6 Illinois, Iowa, Massachusetts, Michigan, Montana, New Jersey, New Mexico, New York,  
7 Ohio, Rhode Island, Vermont, Virginia and the Provinces of Alberta, British Columbia,  
8 Nova Scotia, and Saskatchewan in Canada. I was an invited speaker at the NARUC  
9 Introductory Regulatory Training Program and a panelist at a conference on LDC and  
10 Pipeline Ratemaking sponsored by the Institute of Gas Technology. I have presented a  
11 paper on stranded costs at the 21st Annual International Conference of the International  
12 Association for Energy Economics. I have also spoken at several conferences on the  
13 topic of competitive sourcing of electricity for industrial users.

RECEIVED  
AZ CORP COMMISSION

**BEFORE THE ARIZONA CORPORATION COMMISSION**

JIM IRVIN  
Commissioner - Chairman  
RENZ D. JENNINGS  
Commissioner  
CARL J. KUNASEK  
Commissioner

DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION  
OF TUCSON ELECTRIC POWER  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01933A-98-0471

IN THE MATTER OF THE FILING OF  
TUCSON ELECTRIC POWER COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01933A-97-0772

IN THE MATTER OF THE APPLICATION  
OF ARIZONA PUBLIC SERVICE  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01345A-98-0473

IN THE MATTER OF THE FILING OF  
ARIZONA PUBLIC SERVICE COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN  
THE PROVISION OF ELECTRIC SERVICES  
THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

**DIRECT TESTIMONY OF MICHAEL D. McELRATH**

On Behalf of Cyprus Climax Metals Company

1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A. Michael D. McElrath. 1501 W. Fountainhead Parkway, Suite 290, Tempe, Arizona  
3 85285-2015.

4 Q. BY WHOM ARE YOU EMPLOYED?

5 A. Cyprus Climax Metals Company. Currently, I am Cyprus' Manager of Power. In that  
6 capacity I am responsible for energy supply requirements of the company's mining  
7 operations. In the past, I was employed by Phelps Dodge in a similar position.

9 Q. HAVE YOU REVIEWED THE NOVEMBER 4, 1998 SETTLEMENT AGREEMENTS  
10 ENTERED INTO BETWEEN THE ARIZONA CORPORATION COMMISSION  
11 STAFF ("STAFF") AND ARIZONA PUBLIC SERVICE CORP. ("APS") AND STAFF  
12 AND TUCSON ELECTRIC POWER ("TEP")?

13 A. Yes. I have reviewed both of these agreements. I have also reviewed Staff's, APS's and  
14 TEP's pre-filed testimony.

16 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

17 A. I am testifying in these proceedings because Cyprus is extremely concerned about the  
18 severe, and possibly fatal, impacts these settlement agreements will have on its operations  
19 in Arizona if they are approved by the Commission as written. Now, I want to make it  
20 clear from the outset that I do not claim to be an expert on ratemaking, electric generation  
21 and distribution or market power issues. However, I have been involved in the legislative  
22 and Commission proceedings related to competition as well as those involving the Salt  
23 River Project for the last four years. And, I am acutely aware of the impacts these  
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25  
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1 settlement agreements will have on Cyprus, its employees and those businesses providing  
2 goods and services to Cyprus as well as the local governments relying on taxes and  
3 royalties collected from Cyprus.

4 Q. COULD YOU BRIEFLY DESCRIBE CYPRUS' ARIZONA OPERATIONS?

5 A. Yes. Cyprus, Arizona's second largest copper producer, operates 4 copper mines in  
6 Arizona. Cyprus has made considerable investments to keep these mines at the leading  
7 edge of technology and operating efficiency since 1993. The Miami mine, smelter,  
8 refinery and rod mill operation is located in Gila County and employs 920 persons. The  
9 Sierrita mine in Pima County has 770 employees and the Bagdad mine in Yavapai  
10 County employs another 520 persons. These 2200 plus employees receive an average  
11 annual salary of approximately \$45,000, a total annual payroll of nearly \$100 million. In  
12 addition, Cyprus' purchases of goods and services equaled \$243 million in Arizona in  
13 1997. We have estimated that Cyprus is indirectly responsible for another 9200 jobs in  
14 Arizona as a result of these annual purchases of goods and services.

15 Q. HOW MUCH DOES CYPRUS PAY TO TAXING AUTHORITIES ON AN ANNUAL  
16 BASIS?

17 A. In 1997, Cyprus paid sales taxes of \$16.5 million dollars and property taxes of over \$20  
18 million. Obviously, these tax payments are an important revenue stream for local  
19 governments, particularly in Yavapai County (\$6.9 million in property taxes) and Gila  
20 County (\$5.3 million in property taxes) which do not have the significant economic base  
21 that Maricopa and even Pima County enjoy.  
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1 Q. YOU STATED THAT THE SETTLEMENT AGREEMENTS COULD POSSIBLY  
2 HAVE A "FATAL" IMPACT ON CYPRUS. WHAT IS THE CURRENT ECONOMIC  
3 OUTLOOK FOR CYPRUS' ARIZONA OPERATIONS?

4 A. Its very uncertain. Copper is trading today at about \$0.70 per pound, this is the lowest  
5 price in 11 years. In real dollars the current price hasn't been this low since 1928. That  
6 leaves very little room for a return on the company's investment. You see, copper is a  
7 commodity which means Cyprus cannot control the sales price of its product, only the  
8 cost of producing the product. Moreover, Cyprus competes with other copper producers  
9 in the U.S. and worldwide who often have significantly lower costs. That is why the  
10 results of the Commission's decisions regarding deregulation, in particular, these two  
11 settlement agreements, are so important to Cyprus and could be the difference between  
12 mines closing or remaining open.  
13  
14

15 Q. PLEASE EXPLAIN WHAT YOU MEAN?

16 A. Cyprus purchased over 2 billion kWh of electric services in Arizona during calendar year  
17 1997 at a cost of some \$84 million. Power costs are second only to labor as the largest  
18 variable expense in operating the mines, some 20% of variable operating costs. Cyprus  
19 has actively participated in the competition proceedings in Arizona with the prospect of  
20 reducing its power costs and increasing the likelihood that its operations, especially at the  
21 Bagdad mine, remain financially viable.  
22

23 Q. WHO PROVIDES ELECTRIC POWER TO CYPRUS' ARIZONA MINING  
24 OPERATIONS?  
25  
26

1 A. Cyprus purchases electric power from APS, TEP, SRP, the Tohono O'odham Utility  
2 Authority, and 2 distribution cooperatives served by AEPCO. Cyprus is APS's second  
3 largest retail customer, and TEP's largest retail customer. TEP has a special  
4 "interruptible" contract with Cyprus for the Sierrita mine south of Tucson, Cyprus'  
5 largest mining operation in Arizona. This contract allows TEP to terminate or reduce  
6 power delivery when warranted by certain conditions. In 1997, Cyprus purchased 825  
7 million kWh of electric power from TEP.  
8

9 APS serves power to the Bagdad mine under a special contract with Cyprus which  
10 allows APS to "interrupt" service. This contract is scheduled to expire on April 1, 1999.  
11 Last year, Cyprus purchased 585 million kWh of electric service through a single meter  
12 for the Bagdad mine at a cost of \$27.5 million.  
13

14 Q. HAS CYPRUS ANALYZED THE IMPACTS OF THE APS/STAFF SETTLEMENT  
15 ON THE BAGDAD OPERATION?

16 A. Yes, to the extent possible. One of the problems with both settlement agreements is the  
17 missing information, including an estimate of the utilities' stranded costs. I would also  
18 like to point out that Cyprus' Bagdad operation is in a unique and unenviable position:  
19 The Bagdad - APS contract for power delivered to Bagdad is the first major power  
20 contract scheduled to expire following the introduction of competition. The contract does  
21 not contain any rollover or evergreen provision for extension.  
22

23 We have estimated that Bagdad power rates will increase over 12 % or more than  
24 \$3 million per year upon the expiration of the APS contract in April if the APS/Staff  
25 Settlement is approved by the Commission in its current form. Amazingly, Bagdad  
26

1 already pays the highest rate of Cyprus' Arizona operations under the current APS  
2 contract.

3 Q. WHY WILL THE APS/STAFF SETTLEMENT RESULT IN INCREASED POWER  
4 COSTS FOR THE BAGDAD MINE?

5 A. The APS/Staff Settlement makes no provision for special contract customers. Therefore,  
6 when it expires, APS has indicated that Cyprus will be treated as a standard offer  
7 industrial customer. As explained in Jack Davis's Testimony, the APS Direct Access  
8 Extra Large General Service tariff is proposed as a "one size fits all" direct access tariff  
9 for industrial customers. This "one size fits all" approach for industrial class customers is  
10 inequitable because it fails to recognize the unique service situations like Bagdad.  
11

12 Q. WHY SHOULD THESE UNIQUE SERVICE CONDITIONS IMPACT THE COST OF  
13 ELECTRIC POWER?

14 A. APS should be required to provide cost based service for unique service situations such as  
15 Bagdad. Bagdad is the only APS retail customer to receive power at 115,000 volts. No  
16 other APS retail customer is similarly situated. All other customers receive service at  
17 much lower voltage. The Bagdad 115,000-volt transmission line originates in Prescott at  
18 a major substation that APS also uses to serve the City of Prescott. The kWh required for  
19 the entire City of Prescott per year is similar in quantity to that of Bagdad, although the  
20 City has a higher peak demand. Bagdad owns its own step-down transformer from  
21 115,000 volts to distribution voltage. Bagdad also owns, maintains and operates its own  
22 distribution system to distribute the power within the 10 square mile mine area. Cyprus  
23 has worked diligently to reduce costs and improve efficiency at the Bagdad mine. Since  
24  
25  
26

1 1977, Cyprus has made \$3 million worth of capital expenditures to upgrade the APS  
2 system. This has allowed APS to sell Bagdad more power without increasing the cost of  
3 service. If the Commission approves the APS/Staff Settlement, the Commission and APS  
4 will be penalizing Cyprus for these expenditures with higher prices.  
5

6 In addition, as to Distribution and Must Run - The Arizona Independent System  
7 Administrator provides that "must run" units are assigned to the Phoenix area only where  
8 the support is required. Therefore, these costs are not applicable to customers in rural  
9 areas including Yavapai County. Finally, the APS OATT transmission tariff covers  
10 transmission service from 69 kV to 500 kV. Thus, it is reasonable, as SRP and TEP have  
11 done, not to allocate distribution costs to retail service at transmission voltage.  
12

13 Q. DO YOU HAVE ANY CONCERNS WITH THE RECOVERY OF STRANDED  
14 COSTS AND REGULATORY ASSETS PURSUANT TO THE APS/STAFF  
15 SETTLEMENT?

16 A. Yes. There is no doubt in my mind that the combination of a low market generation  
17 credit ("MGC") and a high competitive transition charge ("CTC") will act to stifle  
18 competition. I will leave it to the experts to explain their economic analysis. Suffice to  
19 say that the inordinately high CTC for the industrial class violates the proportionality  
20 requirement of the Commission's Electric Competition Rules and is the main reason for  
21 the expected increase in power costs for the Bagdad mine if the APS/Staff Settlement is  
22 adopted by the Commission.  
23

24 Further, the failure to consider the unique service situation with the Bagdad mine  
25 will be reflected further in APS' stranded cost and regulatory asset recovery. APS and  
26

1 Staff have failed (or refused) to recognize that Bagdad has been 100% instantaneously  
2 interruptible. Bagdad is subject to having power curtailed instantly under certain  
3 conditions by APS. This has allowed APS to meet its obligation to serve with less  
4 investment in generation capacity, a tremendous benefit to APS and all of its other  
5 customers. I believe this is why the Commission's Electric Competition Rules require  
6 that interruptibility be considered in stranded cost recovery. Unfortunately, the APS/Staff  
7 settlement ignores this issue.  
8

9 Q. HAS CYPRUS ALSO CONSIDERED THE IMPACTS OF THE TEP/STAFF  
10 SETTLEMENT?

11 A. Yes. In fact, most of Cyprus' concerns regarding the APS/TEP Settlement are mirrored  
12 in the TEP/Staff Settlement. For example, the same problems exist with respect to the  
13 MGC and CTC. Consumers are being burdened by all manner of above market costs for  
14 many years to come because they are required to pay all costs associated with the  
15 transition to competition, whatever they may be, including the costs to sell TEP's  
16 generation assets. This looks very much like a blank check. In fact, neither agreement  
17 contains estimates of the utilities' stranded costs. In any event, the result of the TEP/Staff  
18 settlement will be an increase in Cyprus' annual power costs for the Sierrita mine.  
19

20 In addition, if TEP's generation assets are sold as called for under the TEP/Staff  
21 Settlement, the price of power sold under the TEP/Sierrita contract will be impacted.  
22 This will be another consequence of the settlement. Of course, as TEP's largest retail  
23 customer, any such changes could ripple through the Tucson economy.  
24  
25  
26

- 1 Q. DOES THE TEP/STAFF SETTLEMENT ADDRESS SPECIAL CONTRACT  
2 CUSTOMERS?
- 3 A. No. The settlement provides only for standard offer direct access service. The settlement  
4 may require Cyprus to move to a standard offer tariff if it wishes to continue receiving  
5 generation service from TEP after its contract expires. The result of moving to standard  
6 offer direct access would be a significant power price increase for Sierrita. As the Sierrita  
7 mine has the distinction of being the lowest head grade operating copper mine in the  
8 world ("head grade" is the % of copper in the native dirt), there is no room in the  
9 operating budget for significant power cost increases.
- 10  
11 Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE DIVESTITURE OF  
12 TEP'S ASSETS UNDER THE TEP/STAFF SETTLEMENT?
- 13  
14 A. Yes. The TEP settlement requires TEP to divest its generation assets in order to recover  
15 100% of stranded costs from customers. This doesn't give TEP any incentive to reduce  
16 these costs or to seek future customer savings for the benefit of customers through  
17 technological and efficiency improvements. Actually, nothing of TEP is required except  
18 to trade some generation assets for some transmission assets on a utility-friendly book  
19 value basis. In return, TEP will continue to recover an authorized double-digit return  
20 instead of simply a return on capital more commensurate with its lowered risk.
- 21  
22 Q. CAN YOU SUMMARIZE CYPRUS' CONCERNS REGARDING THE APS/STAFF  
23 AND TEP/STAFF SETTLEMENT?
- 24 A. Yes. Under the two settlement agreements, Arizona's two largest utilities are getting  
25 everything they have asked for over the last four years. As a result, all of the risks of  
26

1 competition have been transferred to consumers who will not benefit from competition in  
2 the near future because the MGCs are much less than the generation costs in the direct  
3 access tariffs, to say nothing of any additional burden from securitization for TEP and  
4 other transition related costs.

5  
6 Instead, all of the benefits flow to APS and TEP. After customers are done  
7 paying the fixed costs of APS and TEP's generation assets, these utilities will be able to  
8 sell power at market rates, not cost of service rates, reaping huge windfall profits. For  
9 example, the variable cost of producing power at Palo Verde is less the 1 cent per kWh.  
10 Power sells today for some 2.5 cents per kWh and is increasing faster than the inflation  
11 rate. By the time Palo Verde has been fully paid for by customers, power prices may be  
12 over 3 cents. Indeed, the settlement agreements already have power being sold by APS to  
13 TEP at 3.1 cents per kWh with annual increases thereafter. In addition, utilities are able  
14 to earn their authorized double-digit rate of return on transmission and distribution assets  
15 on a no risk basis.  
16

17 This is not competition and customers are not well served. Competition is alive  
18 and well when customers can save money and improve the level and number of services  
19 offered. Customers are further served when the utility has incentive to improve services  
20 and/or reduce costs. Neither of the settlement agreements accomplishes these goals and  
21 they provide no real incentive for TEP or APS to further reduce their costs of service.  
22 The agreements also fail to require APS or TEP to provide cost of service rates for unique  
23 customers.  
24  
25  
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1 Q. DOES THAT CONCLUDE YOUR TESTIMONY?

2 A. Yes.

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Nov 30 10 52 AM '98

**BEFORE THE ARIZONA CORPORATION COMMISSION**

JIM IRVIN  
Commissioner - Chairman  
RENZ D. JENNINGS  
Commissioner  
CARL J. KUNASEK  
Commissioner

DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION  
OF TUCSON ELECTRIC POWER  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01933A-98-0471

IN THE MATTER OF THE FILING OF  
TUCSON ELECTRIC POWER COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01933A-97-0772

IN THE MATTER OF THE APPLICATION  
OF ARIZONA PUBLIC SERVICE  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01345A-98-0473

IN THE MATTER OF THE FILING OF  
ARIZONA PUBLIC SERVICE COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN  
THE PROVISION OF ELECTRIC SERVICES  
THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

**DIRECT TESTIMONY OF JERRY TURNER**

On Behalf of ASARCO Incorporated

1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A. Jerry Turner. 1150 N. 7<sup>th</sup> Ave. Tucson, Arizona 85703-0747

3 Q. BY WHOM ARE YOU EMPLOYED?

4 A. ASARCO Incorporated ("ASARCO"). Currently, I am the Energy manager for  
5 ASARCO's copper operations, including those in Arizona. My responsibilities include  
6 the purchase of diesel fuel, natural gas, and electric power. I have also held various  
7 positions in the past including Chief Electrical Engineer and Power Engineering  
8 Manager.  
9

10 Q. HAVE YOU REVIEWED THE NOVEMBER 4, 1998 SETTLEMENT AGREEMENTS  
11 ENTERED INTO BETWEEN THE ARIZONA CORPORATION COMMISSION  
12 STAFF ("STAFF") AND ARIZONA PUBLIC SERVICE CORP. ("APS") AND STAFF  
13 AND TUCSON ELECTRIC POWER ("TEP")?  
14

15 A. Yes. I have reviewed both of these agreements. However, our analysis has focused on  
16 the TEP/Staff Settlement in the greatest detail. I would like to point out that I am not an  
17 expert on utility ratemaking, electric power transmission or market power issues, all of  
18 which are obviously raised by these far-reaching agreements. But, I have been involved  
19 with electric power contracts during my career and specifically with the Arizona  
20 deregulation process for the past two years on behalf of ASARCO and I certainly grasp  
21 the impact of these agreements on ASARCO's Arizona operations.  
22

23 Q. IS THAT THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

24 A. Yes. ASARCO operates three different mine sites in Arizona. Two of these mining  
25 operations are located in TEP's service area and ASARCO purchases approximately 500  
26

1 million kWh of electric energy from TEP annually at a cost of approximately \$28 million.  
2 The maximum annual demand is over 70 MW. So, if adopted by the Commission in its  
3 current form, the TEP/Staff Settlement will have a significant impact on ASARCO's  
4 operations in Arizona. By testifying in these proceedings, I hope to make the  
5 Commission aware of that impact and to explain how that impact will also negatively  
6 effect ASARCO's employees and those businesses and taxing authorities that rely on  
7 revenues generated by ASARCO's operations.  
8

9 Q. COULD YOU BRIEFLY DESCRIBE ASARCO'S ARIZONA OPERATIONS?

10 A. Yes. As I said, ASARCO operates three significant mining operations in Arizona. All  
11 three of ASARCO's mining operations in Arizona produce primarily copper. The Ray  
12 Complex, located in central Arizona between Tucson and Phoenix, receives power from  
13 the Salt River Project. This mine complex employs nearly 1,500 persons with an annual  
14 payroll of over \$66 million. Since renovating the site in the early 1980's, ASARCO has  
15 made considerable investment to upgrade the Ray Complex. In addition, ASARCO  
16 annually purchases \$184,000,000 worth of goods and services from Arizona business in  
17 connection with the Ray Complex and pays \$15 million in taxes.  
18

19 Q. WHAT ABOUT THE TWO MINE SITES LOCATED IN TEP'S SERVICE AREA?

20 A. These are Silver Bell Mining, 40 miles northwest of Tucson, and the Mission Complex,  
21 located 18 miles south of Tucson. ASARCO employs roughly 1100 people at the two  
22 mine complexes with an annual payroll of \$42 million. ASARCO purchases over \$100  
23 million of goods and services in Arizona in connection with these two operations, 75% of  
24 which are in Pima County. These mines also generate nearly \$8 million of Arizona taxes  
25  
26

1 and nearly \$8 million in state and tribal royalties.

2 Q. ARE ASARCO'S ARIZONA BUSINESS OPERATIONS PROFITABLE?

3 A. No, not at current copper prices. Copper is currently selling at about 70 cents per pound,  
4 well below the cost to produce it. ASARCO cannot govern the price at which it sells  
5 copper; it can only attempt to control its production costs. Accordingly, major cost  
6 reduction efforts are now underway at all of ASARCO's operations. After payroll,  
7 ASARCO's greatest expense is electric power. We must find ways to reduce those costs.

8 Q. HOW IS THE RATE PAID BY ASARCO FOR ELECTRIC POWER FROM TEP  
9 DETERMINED?  
10

11 A. ASARCO has "special contracts" with TEP. For the Mission Complex, these contracts  
12 contain incentives negotiated to defer ASARCO's installation of cogeneration facilities,  
13 and they also contain interruptible provisions which allows TEP to reduce its power  
14 supply to ASARCO at times of system difficulties or high costs. In addition, industrial  
15 rates in general reflect the lower unit cost of servicing large accounts, the minimal  
16 distribution equipment requirements, and the efficiencies of high load factor, around-the-  
17 clock operations. These current contracts expire between March 1, 2000 and March 1,  
18 2002.  
19

20 Q. SO THE RATES PAID BY ASARCO ARE VERY LOW?  
21

22 A. On the contrary, they are very high. In fact, these costs are 56% higher than those paid by  
23 ASARCO in a neighboring state. Further, due to certain escalation provisions, these  
24 costs now exceed self-generation costs by approximately 50% to 70%.

25 Q. WHY WAS IT IN THE PUBLIC INTEREST FOR ASARCO TO PURCHASE POWER  
26

1 FROM TEP INSTEAD OF COGENERATING?

2 A. ASARCO is TEP's second largest customer, accounting for about seven percent of TEP's  
3 1996 retail electrical load. If ASARCO were to leave TEP's system, other customers  
4 would have to cover that portion of TEP's fixed costs. By covering a portion of those  
5 fixed costs, ASARCO helps lower costs to other customers, including residential  
6 customers.  
7

8 Q. HAS ASARCO MEASURED THE ECONOMIC IMPACT OF THE TEP/STAFF  
9 SETTLEMENT?

10 A. That question strikes at the heart of the problem with the TEP/Staff Settlement. It is, in  
11 fact, impossible to quantify the cost to customers. There are too many unknowns and  
12 contingencies in this settlement agreement. Customers must oppose any agreement  
13 wherein they are blindly bound to pay an open-ended amount determined by others.  
14 Moreover, since the TEP/Staff Settlement appears to give TEP every right, guarantee, and  
15 assurance, it can only be to the customers' detriment.  
16

17 Q. GIVE SOME EXAMPLES OF THESE UNKNOWN FACTORS?

18 A. ASARCO could ask many detailed questions involving generation asset valuation, book  
19 values, agreed upon market values, equity accounting, sole and absolute discretion,  
20 confidentiality, recovery of costs, residual ICTC, inclusion of interest and taxes,  
21 Commission intent, net revenues lost, allocation of negative stranded costs, transition  
22 property, gross-up factors, auction protocols, failed auctions, transcos and ISOs, sale of  
23 SRP transmission lines, capital structure, affiliates, waivers and partial waivers.  
24 However, the changes required in the agreement probably would not be accepted for  
25  
26

1 implementation within the existing framework. Therefore, the best action is not to  
2 approve the TEP/Staff Settlement, or for that matter, the APS/Staff Settlement.

3 Q. IF THE TEP/STAFF SETTLEMENT IS NOT GIVEN APPROVAL, WON'T  
4 COMPETITION FOR ELECTRIC POWER GENERATION IN ARIZONA BE  
5 DELAYED?  
6

7 A. Unfortunately, it may. California had to delay its deregulation process by three months  
8 for technical reasons. While we have worked hard to ensure that competition goes  
9 forward as scheduled, in our view, a three-month delay in Arizona to correct fundamental  
10 structural flaws would be preferable to the proposed TEP/Staff Settlement..

11 Q. WHAT ARE THE STRUCTURAL FLAWS ASARCO SEES?

12 A. There are four basic problems from the customers' prospective: First, the TEP/Staff  
13 Settlement appears to be written for the exclusive benefit of the affected utilities.  
14 Customers had been a part of the prior two years of rulemaking but were excluded from  
15 these negotiations. Second, there is a rush to judgment in approving both settlement  
16 agreements. The utilities had months to consider the benefits they would realize under  
17 the agreements, whereas the customers are expected to analyze the whole package in a  
18 matter of days. Third, the attempt to make the settlement agreements unalterable is  
19 suspect. A good agreement would stand on its merits. Fourth, there would still be no  
20 choice and no competition. The magnitude of TEP's estimates of stranded costs will  
21 mean there will be no benefits from competition for 10 years. Moreover, enforcing the  
22 settlement agreements will require more regulation, not less.

23 Q. WHAT ALTERNATIVE DOES ASARCO RECOMMEND?  
24  
25  
26

1 A. At the conclusion of the Commission's expedited hearing schedule regarding these two  
2 settlement agreements, the Commission should reject them both. Then, with the same  
3 zeal by which they reached the agreements with TEP and APS, the Staff can start  
4 continuous negotiations with all stakeholders until new agreements that protect all  
5 parties, not just TEP and APS, are reached.  
6

7 Q. ARE THERE ANY FURTHER COMMENTS YOU WOULD LIKE TO MAKE AT  
8 THIS TIME?

9 A. Yes. ASARCO has actively participated in the efforts of the Legislature, the Commission  
10 and other to effectuate the introduction of competition for electric generation in Arizona.  
11 Frankly, ASARCO saw competition as an opportunity to reduce its operating expenses  
12 thereby increasing the chance that ASARCO's operations in Arizona remain  
13 economically viable despite the low price of copper. Because the TEP/Staff Settlement  
14 will not promote meaningful competition in TEP's service area, and will likely result in  
15 increased power costs for ASARCO's operations, Commission approval of the agreement  
16 as written will undermine that financial viability. While this will certainly impact  
17 ASARCO's bottom line (i.e.—its shareholders), it will also have profound impacts on  
18 ASARCO's employees and the thousands of Arizonans benefiting from the revenue  
19 stream resulting from ASARCO's purchases of goods and service.  
20

21 Q. DOES THAT CONCLUDE YOUR TESTIMONY?  
22

23 A. Yes it does.  
24  
25  
26

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

Nov 30 10 52 AM '98

JIM IRVIN  
Commissioner - Chairman  
RENZ D. JENNINGS  
Commissioner  
CARL J. KUNASEK  
Commissioner

DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION  
OF TUCSON ELECTRIC POWER  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01933A-98-0471

IN THE MATTER OF THE FILING OF  
TUCSON ELECTRIC POWER COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01933A-97-0772

IN THE MATTER OF THE APPLICATION  
OF ARIZONA PUBLIC SERVICE  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01345A-98-0473

IN THE MATTER OF THE FILING OF  
ARIZONA PUBLIC SERVICE COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN  
THE PROVISION OF ELECTRIC SERVICES  
THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

**DIRECT TESTIMONY OF SYDNEY HOFF HAY**

On Behalf of Arizonans for Electric Choice and Competition

1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A. Sydney Hoff Hay. My business address is 2927 N. 2<sup>nd</sup> Street, Phoenix, Arizona 85012.

3 Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

4 A. On behalf of Arizona Mining Industry Gets Our Support ("AMIGOS"). I am the

5 Executive Director of AMIGOS. AMIGOS is an organization made up primarily of

6 businesses who supply goods and services to Arizona's mining industry. The

7 organization was formed to provide a strong voice in Arizona for the mining industry,

8 and, specifically, the hundreds of small businesses that rely on this industry for their

9 economic well-being.

10

11 Q. HAVE YOU PARTICIAPTED IN THE ARIZONA CORPORATION COMMISSION'S

12 PROCEEDINGS REGARDING THE INTRODUCTION OF RETAIL COMPETITION

13 FOR ELECTRIC POWER SUPPLY?

14

15 A. Yes I have. AMIGOS is a member of Arizonans for Electric Choice and Competition

16 ("AECC"). In my capacity as AMIGOS' Executive Director I have worked closely with

17 the AECC, and its members in the mining industry, to follow and evaluate the impacts of

18 deregulation on AMIGOS' membership. Obviously, if the introduction of competition

19 will have a significant impact on Arizona's mining industry, it will also have a significant

20 impact on the businesses whose members comprise AMIGOS.

21

22 Q. HAVE YOU REVIEWED THE NOVEMBER 4, 1998 SETTLEMENT AGREEMENTS

23 ENTERED INTO BETWEEN THE ARIZONA CORPORATION COMMISSION

24 STAFF ("STAFF") AND ARIZONA PUBLIC SERVICE CORP. ("APS") AND STAFF

25 AND TUCSON ELECTRIC POWER ("TEP")?

26

1 A. Yes. However, I do not profess to understand all of their provisions, especially those  
2 relating to stranded cost and regulatory asset recovery, market power issues or electric  
3 power transmission.

4 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

5 A. It is AMIGOS' desire to make the Commission aware of the impact that the mining  
6 industry has on the economic well-being of the State of Arizona and its citizens.  
7 Although I am not competent to testify as to all of the negative impacts the two  
8 settlements will have on the mining industry, I am well aware of the negative impact the  
9 agreements could have on AMIGOS' members if the Commission's adoption of the  
10 settlement agreements negatively impacts the mining industry.

11 Q. WHAT IS THE SCOPE OF ARIZONA'S COPPER MINING INDUSTRY?

12 A. Arizona copper mining businesses mined and processed 66% of the copper mined in this  
13 country last year. These businesses have mining and processing operations in Cochise,  
14 Gila, Greendale, Mojave, Pima, Pinal and Yavapai Counties. In addition, each of  
15 Arizona's four major copper producers have national or regional headquarters in Pima  
16 and Maricopa Counties.

17 Q. CAN YOU BRIEFLY DESCRIBE THE IMPACT OF THE MINING INDUSTRY ON  
18 THE ARIZONA ECONOMY?

19 A. Yes. The total economic benefit to the State of Arizona from the copper mining industry  
20 in 1997 was equal to \$10.4 billion. Despite copper trading at its lowest price in over a  
21 decade, that amount reflects more than three times the economic impact of copper in  
22 Arizona the previous year. This further reflects the industry's continued high level of  
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1 activity in Arizona.

2 In total, Arizona copper mining provided 82,000 jobs, \$2.637 billion of personal  
3 income and \$7.3 billion in sales revenues for other Arizona businesses. Over 12,000  
4 Arizonans were directly employed in the production of copper at an average annual salary  
5 of \$46,000 for a total payroll of nearly \$600 million. Copper provides one of the highest  
6 rates of pay in the state, exceeding the manufacturing average by 10%. Indirectly, copper  
7 mining was responsible for 70,000 additional jobs as a result of copper industry spending.  
8

9 Q. WHAT ABOUT REVENUE FOR LOCAL AND STATE GOVERNMENTS?

10 A. Again, the impact of copper mining is very significant. The total revenues provided to  
11 government in Arizona equaled \$429 million as a result of copper mining. The direct  
12 payments by the copper industry amounted to \$124 million, 36% of which (some \$44.5  
13 million) went to Arizona's public schools.  
14

15 Q. WHAT IS THE SOURCE OF THE ECONOMIC INFORMATION YOU HAVE  
16 PROVIDED IN YOUR TESTIMONY?

17 A. This information comes primarily from the "Leaming Report", a report prepared by  
18 George F. Leaming, Ph.D. of the Western Economic Analysis Center. The report is titled  
19 "The Economic Impact of the Arizona Copper Industry 1997." I can provide copies of the  
20 report upon request.  
21

22 Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO ADD TO YOUR  
23 TESTIMONY AT THIS TIME?

24 A. Yes. The economic impact of the copper mining industry in Arizona speaks for itself in  
25 the numbers I have testified to above. I think the Commission needs to remember that  
26

1 these are not just mere numbers, however. These numbers reflect the well being of a  
2 large number of Arizona's citizens as a result of copper mining. That well being cannot  
3 be replaced by a competitive marketplace for electric power that will not result in lower  
4 power costs for Arizona's mining industry, which I fear is the best we can hope for if the  
5 Commission chooses to approve the two settlement agreements.  
6

7 Q. DOES THAT CONCLUDE YOUR TESTIMONY?

8 A. Yes.  
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Nov 30 10 52 AM '98

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

JIM IRVIN  
Commissioner - Chairman  
RENZ D. JENNINGS  
Commissioner  
CARL J. KUNASEK  
Commissioner

IN THE MATTER OF THE APPLICATION  
OF TUCSON ELECTRIC POWER  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01933A-98-0471

IN THE MATTER OF THE FILING OF  
TUCSON ELECTRIC POWER COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01933A-97-0772

IN THE MATTER OF THE APPLICATION  
OF ARIZONA PUBLIC SERVICE  
COMPANY FOR APPROVAL OF ITS PLAN  
FOR STRANDED COST RECOVERY

DOCKET NO. E-01345A-98-0473

IN THE MATTER OF THE FILING OF  
ARIZONA PUBLIC SERVICE COMPANY  
OF UNBUNDLED TARIFFS PURSUANT TO  
A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN  
THE PROVISION OF ELECTRIC SERVICES  
THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

**DIRECT TESTIMONY OF LEE JESTINGS**

On Behalf of Enron Corp.

1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS  
2 A. My name is Lee Jestings and my business address is 12647 Alcosta Boulevard, San  
3 Ramon, California 94583.  
4 Q. BY WHOM ARE YOU EMPLOYED, AND IN WHAT CAPACITY?  
5 A. I am a Senior Vice President for Enron Energy Services (EES).  
6 Q. WHAT ARE YOUR RESPONSIBILITIES?  
7 A. I am responsible for managing EES's Western Region. I am an officer of EES and I  
8 report to EES's Office of the Chairman. I am also responsible for the Arizona market and  
9 I will be responsible for making the ultimate decision about EES's involvement in  
10 Arizona.  
11 Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.  
12 A. I was the President of a 65-year old, 250 person energy, engineering, management and  
13 construction company that was purchased by EES. I have extensive experience working  
14 with major manufacturing, industrial, commercial, government and utilities throughout  
15 the Western United States. I am also a licensed professional engineer in California.  
16 Q. PLEASE SUMMARIZE YOUR EDUCATIONAL EXPERIENCE.  
17 A. I was raised in Arizona and received my B.S. in Civil Engineering from the University of  
18 Arizona. I am also completing my MBA from the Haas School of Business at the  
19 University of California, Berkeley.  
20 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?  
21 A. I believe that the proposed settlement will not result in a marketplace with significant  
22 competition for energy generation and that Arizona customers will not receive the  
23 benefits of competition that have been promised to them. I believe that the lessons  
24 learned in California can help the Commission improve the Arizona rules and make  
25 deregulation successful in Arizona. My testimony is intended to make the Commission  
26

1 aware of these concerns and the options for improving the prospects for competition in  
2 Arizona.

3 Q. PLEASE DESCRIBE YOUR INVOLVEMENT IN CALIFORNIA AS IT MOVED TO  
4 RETAIL COMPETITION.

5 A. I have been involved with California's electricity deregulation since the beginning. I  
6 have dealt with all energy players including Investor Owned Utility executives,  
7 commissioners, state senate and assembly members, suppliers, and vendors. Most  
8 importantly, I have extensive experience with California business customers and I have  
9 been involved with some of the largest direct access contracts ever executed in the U.S.

10 Q. WHAT TYPE OF COMPETITION DID THE CALIFORNIA RESTRUCTURING  
11 LAWS ATTRACT?

12 A. In June of 1997 there were approximately 25 large companies stating a commitment to  
13 the commercial and industrial market in California. As of April 1, 1998 (the direct access  
14 start date), only eight companies were involved. Today, there are only three to four  
15 ESP's active in the market. Currently, EES has only one competitor for contracts  
16 covering the bundling of wide-ranging energy services.

17 Q. WHY DID SO MANY ESP'S PULL OUT OF THE CALIFORNIA MARKET?

18 A. There is very little, if any, commodity margin for serving California customers on a short  
19 term (less than four years) basis. At the same time, the costs to properly deliver  
20 electricity, billing and metering services are very high. Many ESP's have not been able  
21 to deliver other value that can overcome low commodity margin and high setup and  
22 customer acquisition costs.

23 Q. WHAT DO CUSTOMERS DESIRE TO SELECT DIRECT ACCESS?

24 A. Customers want commodity savings, energy services, and energy information from a  
25 credible partner that will be there for the long term. They want simple energy pricing and  
26

1 convenient billing. Customers will not go direct access until they feel that they can  
2 realize significant but uncomplicated savings.

3 Q. WHAT COMMODITY PRICING STRUCTURE WAS MOST FAVORED BY  
4 CALIFORNIA COMMERCIAL AND INDUSTRIAL CUSTOMERS?

5 A. Customers want simple, all inclusive discounts off their energy bill (tariff). 95% of  
6 EES's California customers have inclusive (including billing and metering) "tariff minus"  
7 pricing.

8 Q. WHAT DOES IT TAKE TO BE ABLE TO PROVIDE "TARIFF MINUS" PRICING?

9 A. To provide "tariff minus" pricing, the ESP has to price risk related to transmission,  
10 distribution, CTC, load profile, billing and metering costs. The proposed settlements  
11 with APS and TEP prevent "tariff minus" pricing because of the potential for the utilities  
12 to overcollect CTC's. At a minimum, a quantified value of stranded costs must be  
13 prudently set by the Commission. In addition, a fixed cost mechanism for collecting these  
14 costs is recommended.

15 Q. HAVE THE CALIFORNIA CUSTOMERS THAT HAVE GONE DIRECT ACCESS  
16 RECEIVED ANY VALUE?

17 A. Absolutely. Our business customers have received significant value from direct access.  
18 They have received commodity savings ranging from 3% to 5% off of the total bill, new  
19 energy information systems, new energy conversion assets as well as millions of dollars  
20 of investment in their businesses. However, customers can only receive commodity  
21 savings by entering into long-term (four year or more) tariff minus commodity contracts.

22 Q. HOW DO THE PROPOSED SETTLEMENTS COMPARE TO THE CALIFORNIA  
23 STRUCTURE?

24 A. The proposed settlements with APS and TEP are much worse than the situation in  
25 California and pose substantial barriers to customer choice and customer savings.  
26

1 Q. WHY ARE THE PROPOSED ARIZONA RULES WORSE THAN CALIFORNIA?

2 A. Several reasons. First, it is very important to understand what business customers want.  
3 They want short term energy savings and long term value in a simple, hassle free manner.  
4 In my testimony above, I have described some of the issues raised by the settlement  
5 agreements' failure to quantify stranded costs and the mechanisms to collect them. Tariff  
6 minus pricing is absolutely necessary for customers to go direct access. Customers don't  
7 necessarily want several energy suppliers. The proposed Arizona rules prevent this from  
8 occurring. In addition, Arizona has other rules that will affect customers for up to six  
9 years. This makes things worse than California. For example:

- 10 • California allowed immediate, 100% direct access participation; Arizona allows  
11 only 20%.
- 12 • California allows access to all meters; Arizona allows access to meters greater  
13 than 40KW.
- 14 • California has a four year transition period; Arizona has a six year transition  
15 period.
- 16 • California has strict utility marketing affiliate rules; Arizona rules are weak by  
17 comparison.
- 18 • California rules allow tariff minus pricing; Arizona rules do not.
- 19 • California rules apply across most of the state; Arizona rules are being applied  
20 differently between the two major utilities.

21 Q. IS THERE ANYTHING ABOUT THE ARIZONA RULES THAT ARE BETTER  
22 THAN CALIFORNIA

23 A. Potentially there is one major advantage. If structured properly, the MGC may allow  
24 Arizona consumers to achieve immediate savings with short-term contracts, unlike the  
25 California rules. Unfortunately, the proposed settlements preclude this opportunity. The  
26 current MGC calculation provides very little short term savings because it does not cover

1 billing, metering and customer acquisition costs.

2 Q. WHAT CAN THE COMMISSION DO TO IMPROVE THE ARIZONA RULES?

3 A. EES believes that Arizona's consumers can have choice and real savings if the  
4 Commission and the utilities make, among other things, two simple changes to the  
5 proposed settlement.

6 **First, quantify stranded costs and do not allow utilities to overrecover these**  
7 **costs.** This is not fair to Arizona businesses. This also prevents Arizona customers from  
8 obtaining "tariff minus" pricing from ESP's and eliminates long term energy savings  
9 options for customers.

10 **Second, remove costs for ancillary and other services from the adder in the**  
11 **MGC calculation and increase the amount of the adder significantly (double its**  
12 **current value).** The proposed adder in the MGC credit is insignificant especially when  
13 the ancillary costs and other services are included. EES recommends that the costs for  
14 ancillary charges and other services either be paid by the UDC or added to the UDC  
15 CTC amount. This improved MGC will promote robust competition and deliver real  
16 customer choice.

17 Q. DO YOU THINK THE PROPOSED SETTLEMENT AGREEMENTS WITH APS AND  
18 TEP WILL RESULT IN SIGNIFICANT COMPETITION?

19 A. No. Arizona will have fewer competitors than California. Customer choice will be  
20 limited to ratepayer subsidized Arizona utility marketing affiliates with minimal  
21 experience and a couple of state utility marketing affiliates. These utility marketing  
22 affiliates will limit their Arizona presence to a few sales people. If they don't pick up  
23 customers quickly, they will leave.

24 Q. DOES THAT CONCLUDE YOUR TESTIMONY?

25 A. Yes, it does.  
26

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Commissioner - Chairman  
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DOCKET NO. E-01933A-97-0772

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DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN  
THE PROVISION OF ELECTRIC SERVICES  
THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

DIRECT TESTIMONY OF THOMAS EDWARD DELANEY

On Behalf of Enron Corp.

1 Q. PLEASE STATE YOUR NAME, WHO YOU ARE EMPLOYED BY AND YOUR  
2 EDUCATIONAL AND EMPLOYMENT BACKGROUND.

3 A. My name is Thomas Edward Delaney. I have been with Enron since July 1997, and I am  
4 currently the director of Federal Regulatory Affairs, Enron in the West. Before my  
5 employment with Enron, I was employed with the Bonneville Power Administration from  
6 December 1990. While at Bonneville I served in many capacities, including Revenue  
7 Analyst, Contract Negotiator and Fields Contracts Manager. I was also involved in  
8 Bonneville's efforts to address California marketing and restructuring issues.

9 In 1985, I received a Bachelor of Business Administration (BBA) from the  
10 University of Portland in Business Management. In 1989, I received two more BBA's,  
11 one in Marketing and the other in Accounting.

12 Since joining Enron, most of my time has involved dealing with issues throughout  
13 the West, such as the California ISO, IndeGO, Desert Star, California open access,  
14 Arizona open access, Nevada open access, Northwest Regional Transmission Association  
15 (NTRA), Western Regional Transmission Association (WRTA), Southwest Regional  
16 Transmission Association (SWRTA), Western State Coordination Council, (WSCC), the  
17 Western Interconnection Conference Forum (WICF), as well as other commercial and  
18 FERC related issues.

19 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

20 A. To discuss the proposed settlement agreements of the Arizona Corporation Commission  
21 Staff with Tucson Electric Power (TEP) and with Arizona Public Service (APS).

22 Q. WHAT ARE YOUR CONCERNS WITH THE SETTLEMENTS?

23 A. Transco's, competition, mitigation of market power, divestiture, and open access are all  
24 issues Enron endorses, if brought about correctly. Although I support the movement  
25 toward a Transco, as described herein, the proposed settlements will not provide Arizona  
26

1 with competitive generation markets or mitigation of vertical and horizontal market  
2 power. These settlement agreements fall short of their intended target.

3 TEP will not be a true Transco because it will still have generation facilities, a  
4 distribution merchant function, and marketing affiliates in its portfolio mix. TEP will  
5 retain all of the incentives for self-dealing it has today. If TEP divested all its generation,  
6 affiliate marketing functions, and mitigated its distribution merchant function role, it  
7 would begin to resemble a Transco.

8 With respect to APS, APS will increase its generation portfolio and increase its  
9 horizontal market power while retaining control of 230KV and below transmission  
10 facilities and all of its contractual rights on other transmission systems. In my opinion,  
11 this will create a new and larger vertically integrated APS utility with **more** horizontal  
12 market power and none of the benefits of restructuring. Furthermore, the settlements  
13 raise concern regarding the role of the Arizona Independent Scheduling Administrator  
14 (AISA).

15 Q. WHAT DO YOU THINK OF THE ARIZONA CORPORATION COMMISSION  
16 CREATING AN ARIZONA TRANSCO?

17 A. A Transco is preferential to an Independent System Operator and even, ISA's. However,  
18 a properly structured Transco should be in the transportation business only. If the  
19 Commission creates a Transco with the right economic incentives, it would have  
20 considerable incentives to take on more risk than transmission companies do today. We  
21 would see more transmission built where needed, throughput increased, debt retirement  
22 accelerated, pancaked rates disappearing, and vertical market power mitigated.  
23 Unfortunately, TEP -- with generation, marketing affiliates, and merchant functions  
24 remaining in its mix -- cannot be realistically seen as a Transco.

25 Even if the generation, marketing affiliate, and merchant function problems could  
26 be resolved, TEP would need to have all of Arizona's transmission facilities under its

1 control. Although the TEP/Staff Settlement Agreement provides that TEP will also  
2 acquire the transmission facilities of SRP and AEPCO, there is simply no mechanism for  
3 ensuring that TEP will eventually acquire all of the transmission facilities in the state.

4 Furthermore, the Commission needs to ensure that transmission and distribution  
5 are not split at the 230/345 KV levels. Under the proposed settlements, APS will transfer  
6 control of its 345 KV and above facilities to TEP while retaining its 230 KV and below  
7 system. Under this split, the settlements seek to arbitrarily redefine the 230KV and  
8 below systems as distribution facilities. However, in APS's recent Open Access  
9 Transmission Tariff filing with FERC, APS defined the transmission and distribution  
10 split at the 69 KV level. Similarly, in the Desert Star process, 230 KV was never  
11 considered distribution, nor should it be. In short, the Arizona Corporation Commission  
12 should not consider APS's 230 KV as distribution.

13 It is also unclear whether APS will be giving up control of its contractual  
14 transmission rights as well. For TEP, or a Transco, to exist in Arizona, it should control  
15 all transmission assets, including contractual rights to the transfer capability of such  
16 systems. If APS does not transfer these contractual rights, it will remain in the  
17 transmission business with transmission contracts at its disposal. This creates too much  
18 potential for discrimination.

19 In summary, the Commission should continue to work towards the creation of a  
20 Transco. However, this Transco must ultimately include all transmission assets in  
21 Arizona, including those above traditional transmission/distribution split levels, not at  
22 345 KV and above which is arbitrary and merely serves APS' own purposes.

23 Q. PLEASE DISCUSS YOUR CONCERNS ABOUT THE AISA.

24 A. I'm very concerned that the role of the AISA will be impaired by the settlement  
25 agreements if they are adopted as written. The AISA's filing defines its responsibilities  
26 in detail. Among other things, these responsibilities include the determination of Total

1 Transfer Capability, Committed Use and Available Transfer Capability, transmission  
2 reservation and allocation processes, transmission scheduling and curtailment processes,  
3 access to commercially significant information, and dispute resolution procedures. The  
4 clear intent of the numerous stakeholders who have participated in the AISA's  
5 development is that the AISA's protocols and procedures will govern in the event of a  
6 conflict. Were this not the case, there would be very little reason for the AISA's  
7 existence.

8 As described in the settlement agreements, there are many prescriptive  
9 requirements in terms of non-discriminatory access that utilities must follow. Such  
10 requirements have implications on the treatment of Total Transfer Capability, Committed  
11 Uses and Available Transfer Capability, transmission reservation and allocation  
12 processes, transmission scheduling and curtailment processes, access to commercially  
13 significant information, and dispute resolution procedures.

14 To date, the AISA has incorporated, has established its Board of Directors,  
15 submitted its filing to FERC, and is continuing its efforts to fulfill its charter. It is  
16 unclear whether, through the settlements, APS, TEP and Staff intend to set up a process  
17 that falls outside the AISA or a process that is senior to the AISA's charter. The  
18 Commission needs to reiterate its commitment to the AISA and to make it clear to all  
19 Arizona utilities that they are fully subject to its protocols and rules.

20 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

21 A. Yes, it does.